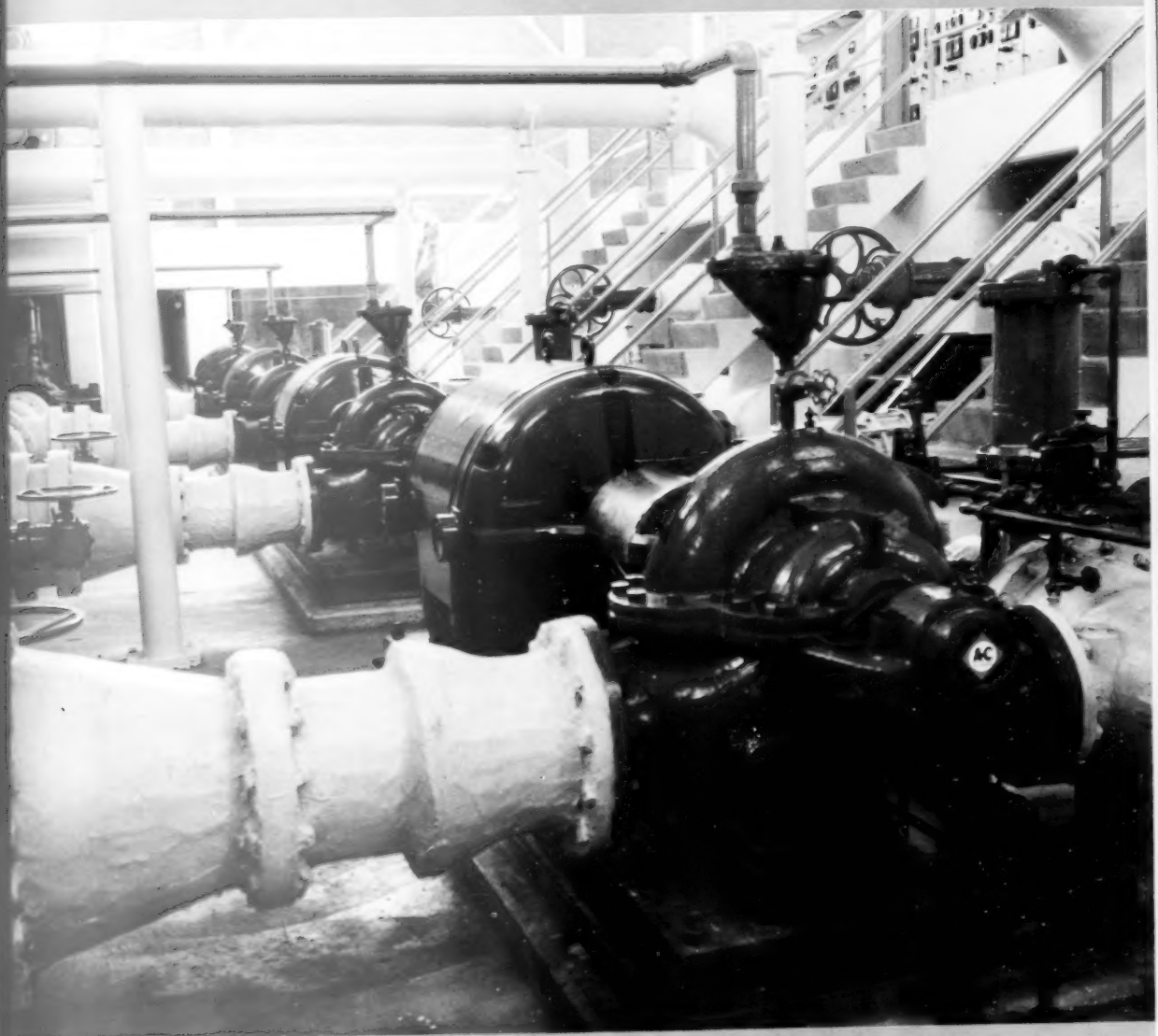
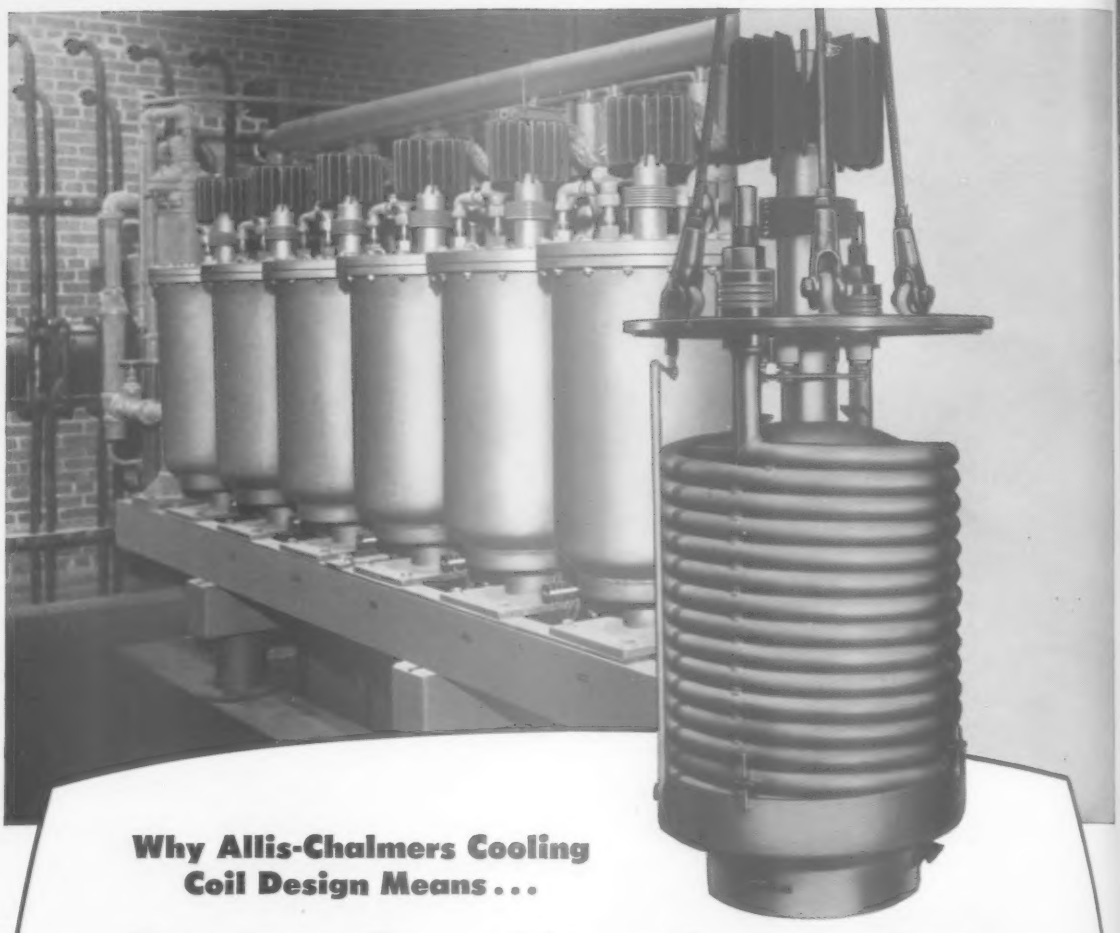
ALLIS-CHALMERS

2ND QUARTER 1956

Electrical REVIEW



HOW TO GET EMERGENCY TRANSFORMER CAPACITY...PAGE 16



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THE COVER

FROM HIGH LINE TO PIPE LINE, all new electrical and mechanical power equipment to impel 13,300 gpm of water from Lake Erie to the City of Elyria, Ohio, was recently installed at this pumping station in Lorain.

In a modernization program, boilers to produce 125 psi saturated steam and three horizontal cross-compound reciprocating steam pumping engines — rated 8-million, 5-million, and 3-million gallons per day, respectively — were replaced by these four 12- by 10-inch centrifugal pumps, their 450 horsepower synchronous drive motors, and the required transformers, switchgear and control.

A-C Staff Photo by J. E. Gosseck

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ELECTRICAL REVIEW

Vol. XXI No. 2

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Issued quarterly. Subscription rates: U. S., Mexico, and Canada, $2.00 per year; other countries, $3.00; single copies, $1.00 in advance.

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Indexed regularly by Engineering Index, Inc.
Allis-Chalmers ELECTRICAL REVIEW is available to public and institutional libraries on microfilm from University Microfilms, 313 N. First St., Ann Arbor, Mich.

Address Allis-Chalmers Electrical Review, Milwaukee 1, Wisconsin

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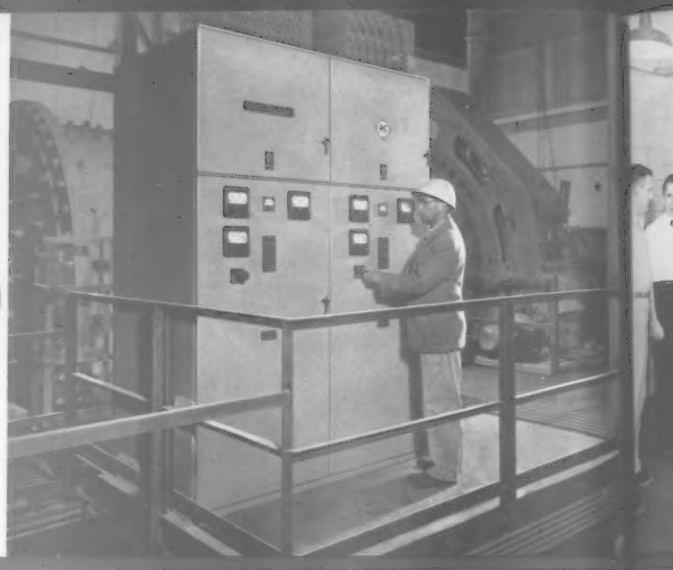
Industrial CONTROL or SWITCHGEAR?



SYNCHRONOUS MOTORS, rated 1000 hp, 2300 volts, drive two 10½ by 17-ft ball mills in an eastern cement plant. Both motors have industrial-type, current-limiting, fused controllers. **(FIGURE 1)**

by H. A. WRIGHT
Ass't Mgr. of Sales
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Here are answers to common questions governing the choice between industrial control and switchgear for 2500 to 5000-volt motors.

MOST ENGINEERS know that control equipment is installed at the point of power utilization, whereas switchgear is used to govern power distribution and to protect the power supply system. They are also familiar with low voltage switchgear and low voltage motor control. Yet there remains a certain amount of confusion that shows up when high voltage contactors are referred to as "breakers," and specifications are written for industrial control based on switchgear standards. Figure 1 shows an industrial control in a cement plant, while Figure 2 shows switchgear being used to control pump motors in a municipal pumping station.

According to NEMA Power Switchgear Standards, power switchgear assemblies include, but are not specifically limited to, equipment for the control and protection of apparatus used for power generation, conversion, transmission, and distribution.

Metal-clad switchgear ratings are 2.5 to 13.8 kv and 25 to 500-mva interrupting capacity. This class of switchgear comprises all indoor and outdoor cubicle-type construction, consisting of metal-enclosed units and auxiliary compartments characterized by the following:

1. All parts are completely enclosed within grounded metal enclosures.

2. Secondary control devices and their wiring are isolated from all high voltage primary devices by grounded metal barriers.

3. Major parts of the primary circuit, such as circuit breakers, transformers and buses, are isolated by grounded metal barriers.

4. The circuit breakers are removable and are equipped with self-coupling primary and secondary disconnecting mechanisms. These mechanisms allow the breaker to be moved either horizontally or vertically to the connected or disconnected positions.

5. Interlocks are provided to insure proper sequence and safe operation.

6. Buses, connections and joints are insulated throughout.

Industrial control, according to NEMA, covers devices whether electric, magnetic, mechanical, or electronic, which, individually or grouped, serve to govern in some predetermined manner the electric power delivered to the apparatus to which they are connected. These devices are intended to function on commercial voltages of 750 volts or less dc and 5000 volts or less ac.

High voltage industrial control equipment is limited to:

a. The use of oil or air circuit breakers[1] with interrupting ratings of 50,000 kva or less and for service voltages up to 5 kv.

b. A combination of properly coordinated fuses and contactors where interrupting capacity requirements do not exceed 150,000 kva at service voltages not exceeding 2500 volts, or where interrupting capacity does not exceed 250,000 kva at service voltages greater than 2500 and not exceeding 5 kv. Fuses with a current-limiting characteristic as shown in Figure 3 are used in modern industrial control.

The standards seem to define the two areas quite clearly. *Switchgear is used for power distribution; industrial control is used for power utilization.* However, in some motor control applications engineers are required to choose between the two types of equipment. Below are

[1] In this case, the circuit breakers referred to in standards are generally contactors.

BOOSTER PUMPING STATION at Greenville, N. C., uses switchgear to control three 500-hp, 2300-volt pump motors. Line-up includes main breaker, auxiliary and three motor feeders. **(FIGURE 2)**

answers to some of the most frequently asked questions regarding control and switchgear applications.

Question: Are there any exceptions to the 5000-volt limitation?

Answer: No, over 5000 volts switchgear must be used. For example, all 6600-volt motors must be controlled by switchgear.

Question: Does high voltage industrial control have any horsepower limitations in its application?

Answer: Industrial control has the following horsepower limitations:

Voltage	*Hp at Unity PF*	*Hp at 80% PF*
2300	1750	1500
4600	3000	2500

Induction motor controllers have the same limitations as 80 percent power factor synchronous motor controllers. Switchgear, on the other hand, has no limitation except that imposed by the circuit breaker (2000 amperes at 5 or 13.8 kv). Figure 4 shows the switchgear used to control a synchronous motor with a rating beyond the range of industrial motor control.

Question: Are there any exceptions to the kva limitation on interrupting capacity?

Answer: No.

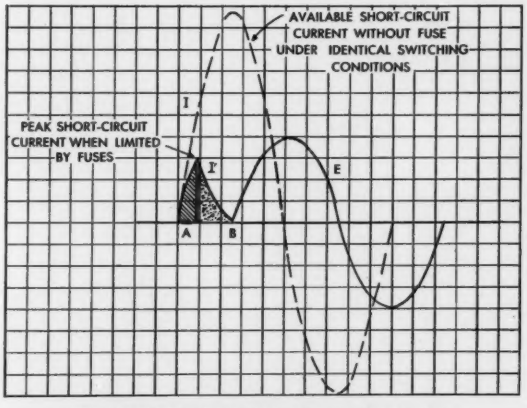
Question: Why have a fused starter? Why not always use switchgear where interrupting capacities of 50,000 kva or more are required?

Answer: To explain these questions it is necessary to go back to the basic difference between contactors used in industrial control and circuit breakers used in switchgear. A contactor is both closed and held closed by means of a magnet. A circuit breaker, on the other hand, may be operated by means of a magnet but is held closed by means of a mechanical latch. Because of the mechanical complications of the latching mechanism, the circuit breaker is not normally used to control motors which are started or stopped frequently.

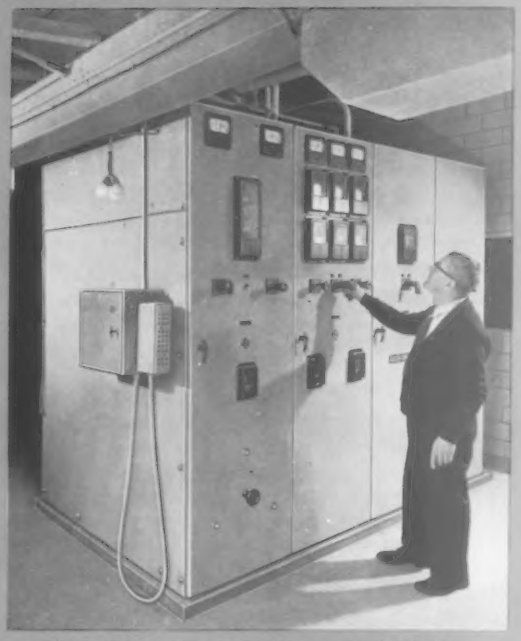
Question: Why use fuses for short-circuit protection? Why not let the feeder breaker in the switchgear do the job?

Answer: Control engineers say that if the capacity of the line is greater than 50,000 kva, current-limiting fuses must be used. High voltage industrial control equipment cannot be protected by a backup breaker. Here again it is necessary to go back to the difference between the breaker and the contactor. The contactor is magnetically held and the breaker is held by means of a latch. In other words, the contactor requires voltage in order to keep it closed. A short circuit on the phase supplying the contactor holding coil will result in the loss of sealing power and the contactor will drop open. Its dropout time is approximately 4½ cycles.

High speed backup breakers are considered fast if of the 8-cycle variety and are normally set somewhat longer. When using backup breakers, there is a zone from the time the contactor drops (4½ cycles) to the time that the backup breakers open (8 to 20 cycles) that the contactor arcs severely, since it cannot interrupt the current over its rating. Oil-immersed contactors will explode and air contactors will be severely damaged. Therefore, high capacity, high speed fuses were developed to provide the protection that cannot be provided by circuit breakers. These fuses are designed to blow in less than ½ cycle, as shown in Figure 3, which is considerably less than the 4½ cycles dropout



HIGH INTERRUPTING SPEED of current-limiting fuses prevents short-circuit current from building up to the full system short-circuit capacity. **(FIGURE 3)**



METAL-CLAD 4160-volt switchgear controls 3000-hp, 0.80 pf synchronous grinder motor in paper mill. **(FIG. 4)**

CURRENT-LIMITING FUSES serve as a disconnect switch and provide fast-opening short-circuit protection. **(FIG. 5)**

time of the contactor. This fast fuse operation has resulted in wide application and acceptance of fused controllers like that shown in Figure 5.

Question: What would happen if one of the other phases were shorted?

Answer: Several things might happen: Usually, a single-phase short develops into a three-phase short rather quickly. Furthermore, the unbalance in the three-phase system may cause the voltage in the other phases to drop to the point where the contactor will open. However, if voltage is maintained on the contactor holding coil under these conditions, the line current may be sufficient to cause the contact tips to blow open.

Question: What is meant by "blow open"?

Answer: "Blow open" refers to the parting of contacts under stress of high current. The force on the contacts caused by a short circuit may be sufficient to overcome the contact spring pressure, causing the contacts to part. In a clapper-type contactor the flexible leads will try to straighten out and thereby aid in pulling the contacts apart. Damage resulting from parting contacts, which are carrying high currents, is generally not severe in air contactors, but in oil contactors it is difficult to predict what may happen.

Question: How do the fuses work? It would seem that they would blow on starting current, since they operate so rapidly.

Answer: A fuse is made up of a Pyrex glass barrel filled with pure quartz sand. Running through this sand, from top to bottom connections, are a number of parallel paths of silver wire. The cross section of the wire is tapered toward the center, so that the wire always burns both ways from the center. The current-limiting effect results from the arc resistance. Since the wire burns in both directions, the arc lengthens and its resistance increases.

The arc energy is absorbed by the melting of the quartz sand. Upon inspection of a fuse after it has blown, one will find glass tubes where the arc heat has melted the quartz sand.

Fuses are obtainable in a number of different sizes. The fuse is selected from motor data covering full-load current and maximum inrush current. The energy dissipated by the fuse is based on I^2R. Therefore, a fuse curve plotted as time in seconds to current in amperes will follow a square curve—inverse time characteristic. If the fuse is properly selected, it will not blow on starting current.

Question: Is the current-limiting effect the same for all size fuses?

Answer: No, the larger the fuse rating, the less current-limiting effect.

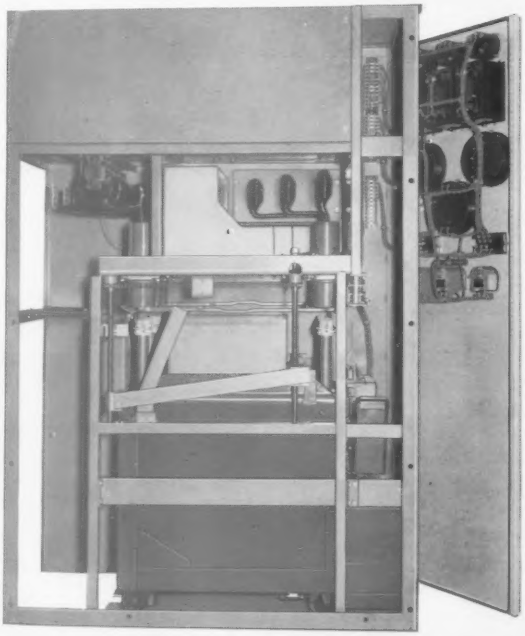
Question: Are the system kva and voltage the only characteristics to check?

Answer: In addition to the kva rating, the maximum rms asymmetrical current available from the power system should not exceed 60,000 amperes.

Question: What does industrial control offer to protect against the possibility of the motor single-phasing?

Answer: Some engineers do not like to use fuses because of the possibility of one fuse blowing, thereby single-phasing the motor. Seldom does only one fuse blow and then only on grounded systems. If the motor is loaded, the thermal overload relays will protect the motor. Except in the case of delta-connected motors, an unloaded motor will not be damaged by single-phase operation. For the ultimate in motor protection a phase failure relay may be added.

Question: Is there much difference in the mechanical arrangements of breakers in the switchgear units and contactors in industrial controllers?



SWITCHGEAR BREAKER serves as disconnect. This 250,000-kva air magnetic vertical lift breaker is shown in its disconnected position. High voltage bus and terminals are insulated. **(FIGURE 6)**

Answer: Yes, the circuit breakers used in switchgear are plug-in. They are of two types: vertical lift or horizontal drawout. A vertical lift breaker is shown in Figure 6. By means of a rack mechanism the breaker may be unplugged (disconnected) and drawn out of the cubicle on its own wheels. The breakers are interchangeable, so that a spare breaker may immediately replace the one being serviced.

The high voltage contactors used in industrial control are stationary devices and are ordinarily serviced in place. A separate disconnect switch is provided with each controller to de-energize the contactor during servicing.

Question: Doesn't switchgear have disconnect switches?

Answer: In switchgear the plug-in arrangement serves as the disconnect means. Since there is no such arrangement in industrial control, a disconnect switch must be used.

Question: The term "roll out" is sometimes used in connection with industrial control. Does this arrangement, like switchgear, provide disconnect means?

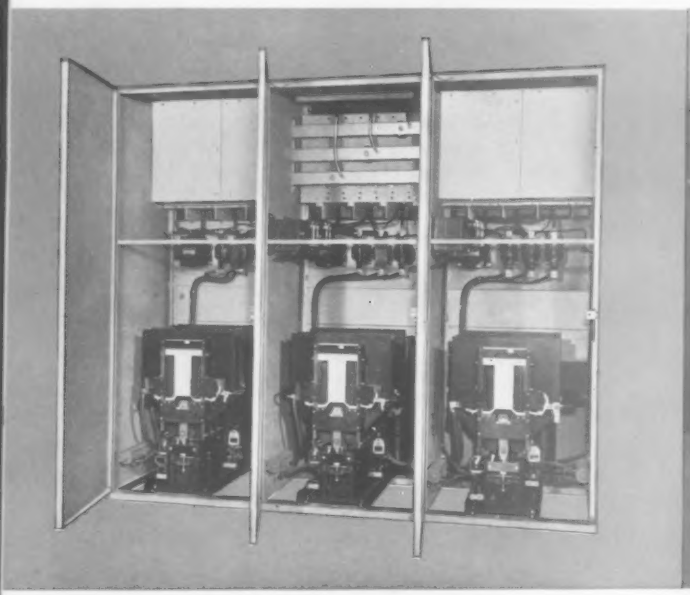
Answer: No. Some of the newer designs of high voltage motor control have removable high voltage contactors mounted on wheels. However, they do not plug in, so the primary leads must be disconnected at the terminals.

Question: How do connections differ for other auxiliary devices used in switchgear and control?

Answer: The potential and control transformers used in switchgear are mounted on wheels and arranged to plug in within a separate compartment. In industrial control they are stationary. Also, most relays used in switchgear are of the plug-in type, while industrial control relays are not.

Question: Is there any difference in the bus arrangements?

Answer: Switchgear uses insulated bus, while industrial control does not. Furthermore, switchgear uses silver-plated bus connections, industrial control does not. The current-carrying capacity of the bus for switchgear is normally 1200, 2000, or 3000 amperes; for industrial control, 1000 to 2000 amperes. Industrial control uses 5000-volt cable to connect the contactor to the main bus. Switchgear uses buswork throughout. Both, however, meet the same dielectric test: 45 kv for a 2.5-kv bus, or 60 kv for a 5-kv bus. Figure 7 shows the rear view of an industrial control line-up.



INDUSTRIAL-CONTROL type reduced-voltage starters are compact. Each unit contains two air contactors and a reactor. **(FIGURE 7)**

SWITCHGEAR CONTROLS one 400-hp and three 800-hp oil pipeli motors. Breakers are rated 150,000 kva, 2400 volts. **(FIGURE**

Question: Why does switchgear use insulated buses?

Answer: As mentioned earlier, switchgear is designed for continuous service on distribution lines. Here continuity and protection of the system are of prime importance. The user is willing to pay more for this insurance. A bus fault in a substation may shut down an entire area, whereas a bus fault in a line-up of industrial controllers would affect only a few motors in one plant.

Question: What are the differences in instrumentation and relays in the two types of equipment?

Answer: Generally speaking, industrial control uses the same type and quality of instruments used on switchgear. The relays, on the other hand, are normally more rugged and less pleasing to the eye. That is why industrial relays are not mounted semi-flush on the front door of the enclosure. On special order switchboard-type relays may be fitted into the control design. A minor difference is that switchgear uses control switches to close its circuit breakers, whereas industrial control uses pushbuttons to control its contactors. Their protective devices differ in contact arrangement—circuit closing on switchgear and circuit opening on control.

Question: Switchgear protects as well as governs the power system. Does industrial control protect as well as govern motors?

Answer: Yes, industrial control provides thermal overload protection on two phases as standard, with an optional addition for the third overload relay. Short-circuit protection is provided by means of fuses or by means of a main switching device (line contactor) having an interrupting capacity up to 50,000 kva. Switchgear, on the other hand, provides both thermal overload and short-circuit protection by means of the switching device and overcurrent relays. Industrial control uses overcurrent relays as standard on high voltage equipment having 50,000-kva interrupting capacity.

Question: In what type of applications should switchgear be recommended in place of industrial control, or vice versa, for motor control?

Answer: A typical application might be a base-load pumping unit on a transcontinental pipeline, with a pump that operates 24 hours a day, day in and day out, and is not frequently started and stopped. Here the motor should be controlled by switchgear, since the breaker or latch device is more desirable for continuous service. Figure 8 shows typical switchgear for oil pipeline service.

On this transcontinental system there might be a feeder line with a pump operated by means of a float switch on a collecting tank. Assuming that the pumping unit starts and stops frequently, industrial control should be

used because a contactor is more suitable for repetitive operation than a circuit breaker.

Question: Are there any common misapplications of industrial control?

Answer: Yes, there is one rather outstanding misapplication—using oil-immersed equipment for jogging duty. Contacts under oil erode 20 to 40 times more rapidly than contactors immersed in air. Another misapplication is the use of a circuit breaker as backup protection for high voltage industrial control.

Question: What type of explosion-proof control is available in this voltage class?

Answer: There is no Underwriters-approved equipment available in the 2300 or 4600-volt class. However, a type of industrial control equipment is available that is as safe as is economically feasible to build. In these controllers the contactors must be oil immersed and are available in sizes up to 50,000-kva interruption capacity. In these units all terminals and connections are also immersed in oil. Beyond 50,000 kva, Class I Group D controllers are available for semi-hazardous locations. In these controllers only the arcing contacts are either immersed in oil or enclosed in explosion-proof housings.

Question: Are switchgear and control ever installed in the same line-up?

Answer: Yes, such an arrangement is quite common. The feeder connects to an interrupter switch which is throat-connected to the transformer. The transformer secondary, in turn, is throat-connected to the distribution switchgear, and a bus transition unit is provided between the gear and the high voltage motor controllers. The switchgear and control line-up is matched to give a pleasing appearance, as shown in Figure 9.

While switchgear and control may be installed in the same line-up, each serves its own basic purpose. One provides control and protection of the power supply, and the other provides control and protection of the motor. It is well to remember these two concepts when coordinating switchgear and control.

Question: Is there a difference in list price between switchgear and control for the same application?

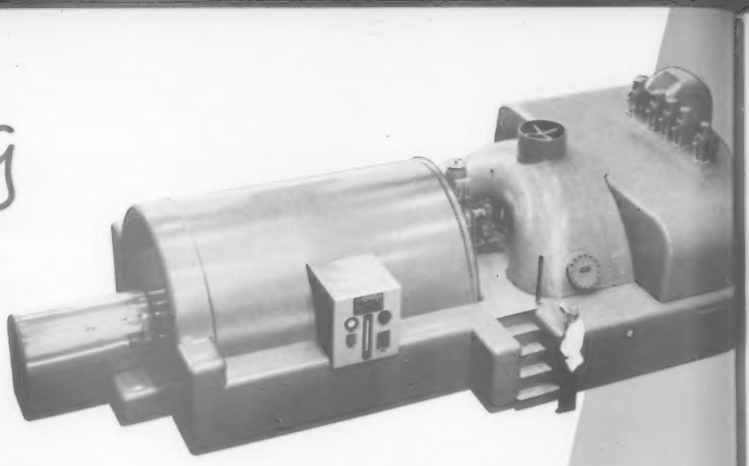
Answer: Yes, the price of industrial control is lower than switchgear.

Question: Are there any particular problems to watch for in specifying control equipment?

Answer: When specifying control equipment, it is important to choose the type of control first (either industrial control or switchgear), based on manufacturer's published information and on industry standards, and then write the specifications based on that type of control. In other words, do not mix nomenclature in the specification.

MULTI-CIRCUIT SUBSTATION has primary disconnect, transformer, switchgear incoming line panel, tie breaker, metering panel and six fused 2300-volt motor controllers. The synchronous motors being controlled are rated 700 and 800 hp, 80 percent power factor. **(FIGURE 9)**

Selecting Excitation Systems FOR TURBO-GENERATORS



THE SMALL EXCITER HOUSING of this 33,000-kw steam turbine-generator unit characterizes the recently developed A-C exciter described as a part of System *D*. (FIGURE 1)

by **H. H. ROTH**
Motor & Generator Dept.
Allis-Chalmers Mfg. Co.

This comparison of the four basic types of automatic excitation systems points up advantages and limitations of each.

EXCITATION SYSTEMS for steam turbine generators have grown in complexity, and the number of systems from which to choose has increased as steam turbine-generator units have become larger and more numerous. While the component parts of certain turbogenerator exciter systems are, in many instances, quite similar to the components for hydro-generator excitation systems,* much higher shaft speeds of turbogenerators modify their application.

An excitation system consists of the equipment necessary to provide two functions: First, it must furnish excitation current to the generator; secondly, it must vary the excitation current to maintain the generator output voltage at the desired value under fluctuating load conditions. In its simplest form, an excitation system consists of an exciter, either direct connected or separately driven, and a manually operated rheostat in either the generator or exciter field circuit to vary the generator field current. While systems of this type were used for early generating units, they are inadequate for modern central-station use.

* "Selecting Excitation Systems for Hydro-Generators," H. H. Roth, 4th Quarter, 1955 ELECTRICAL REVIEW.

Requirements of modern electric power plants have resulted in the development of four basic types of excitation systems for steam turbine driven generators. Their approximate areas of application are indicated in Figure 2. The principal component parts used in these systems are:

System A

1. Direct-connected stabilized main exciter.
2. Direct-acting generator voltage regulator.
3. Hand or motor-operated exciter field rheostat for manual control of generator voltage.

System B

1. Direct-connected or geared main exciter.
2. Direct-connected or geared pilot exciter.
3. Indirect-acting generator voltage regulator.
4. Motor-operated main exciter field rheostat with field-forcing contacts.

System C

1. Direct-connected or geared stabilized main exciter.
2. Rotating-amplifier type generator voltage regulator.
3. Hand or motor-operated main exciter field rheostat for manual control of generator voltage.

System D

1. Direct-connected inductor-alternator type main exciter.
2. Rectifier bank to convert exciter output to dc.
3. Static control elements to regulate generator voltage.
4. Hand or motor-operated control rheostat for manual control of generator voltage.

The component parts of these excitation systems differ to a considerable extent. A comparison of the various

systems will point up the advantages and limitations of each.

Systems *A* and *C* require stabilized main exciters. System *B* does not have this requirement, since its main exciter is in turn excited by the constant voltage pilot exciter.

With Systems *A* and *C*, the main exciter, being self-excited, operates on an excitation voltage that varies with regulator fluctuations. When a self-excited exciter is operated at low voltages, as is often the case under light load conditions or when synchronizing a turbogenerator to the system, a slight change in exciter field current produces a relatively large change in exciter output voltage. Because of this characteristic, accurate control of generator voltage in this range of operation is difficult with an unstabilized self-excited exciter.

To eliminate this difficulty, the main exciters for these systems are specially designed to maintain their voltage stability down to about 25 percent of rated voltage. With Systems *A* and *C* it is possible to use an exciter which is not stabilized if a generator field rheostat is used to insert additional resistance into the generator field circuit. Sufficient resistance is added to require an exciter output voltage high enough to avoid operating the exciter over its unstable voltage range. However, it is general practice to use stabilized exciters rather than generator field rheostats.

System *A* preferred for small generators

This system can be applied to generators rated 25,000 kva or less and designed to operate at speeds 1200 rpm and above. For larger ratings one of the other systems must be used, since the field current of the main exciter becomes greater than can be handled by a direct-acting regulator.

A direct-acting regulator has both the voltage-sensing element and the regulating resistance built into a single, complete unit. Regulators of this type have limited current capacity and can therefore be applied only to exciters requiring relatively small shunt field current — usually under about 25 amperes. A typical *Rocking Contact* direct-acting voltage regulator is shown in Figure 3.

Self-excited main exciters, because their excitation voltages vary with output voltage, require only a relatively small amount of shunt field current. Their current requirements can be met by the physically small resistance elements of the direct-acting regulators.

Direct-acting regulators, however, have only limited application even on small machines if pilot exciters are used. Main exciters that receive their excitation from a constant voltage source, such as a pilot exciter or a station battery, usually require a larger range of regulating resistance than can be built into a direct-acting regulator.

Exciter field resistance in this system can be varied by the use of either a manually operated or motor-driven rheostat. In normal operation, the resistance of this rheostat is completely cut out of the exciter field circuit. In case of difficulty with the voltage regulator, however, it is used for manual voltage control. A rheostat of this type is shown in Figure 4.

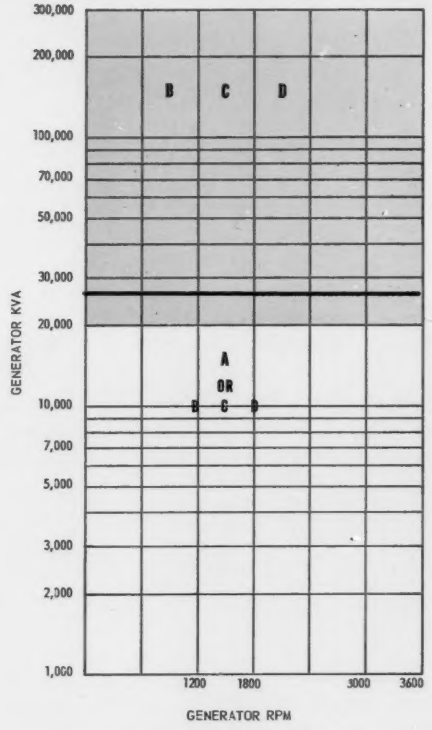
The other excitation systems can also be used with generators not exceeding 25,000 kva, but the cost will be greater.

System *B* is used for larger ratings

An indirect-acting voltage regulator, shown in Figure 5, is one in which the voltage-sensing element does not vary the regulating resistance directly. Instead, the resistance element is a motor-operated main exciter field rheostat. Relatively slow in operation, this rheostat cuts resistance in or out of the main exciter field circuit upon a signal from the voltage-sensing element.

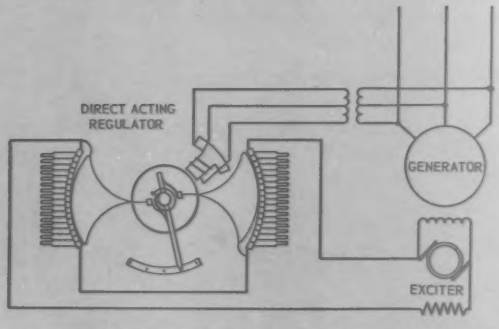
While this action assures sufficiently fast regulation for small voltage changes, field forcing is provided for large changes. This is accomplished by two high speed contactors: a "raise" contactor to short-circuit a portion of the regulating resistance, and a "lower" contactor to insert additional resistance into the main exciter field circuit.

Upon a drop in generator terminal voltage the "raise" contactor closes. This decreases the effective resistance in the exciter field circuit and maintains increased generator excitation until the motor-operated exciter field rheostat

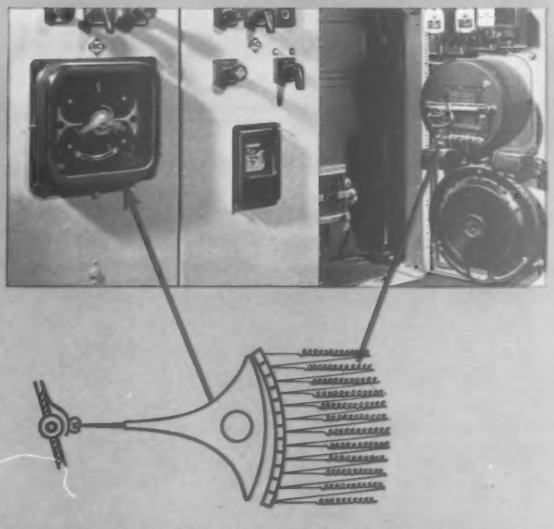


WHILE EXCITATION SYSTEMS *B*, *C*, or *D* can be applied to generators of any rating, for economic reasons they are usually not applied to machines rated less than 20,000 kva. System *A* is limited to machines below 25,000 kva. **(FIG. 2)**

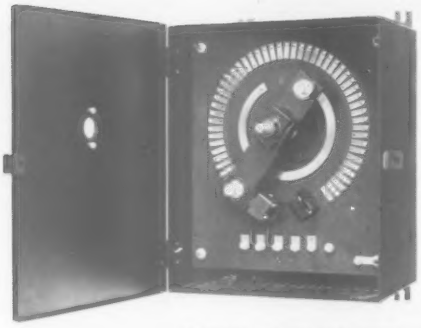
THE DIRECT-ACTING regulator of System *A*, used to control excitation for this 3000-kw generator, is one of the two mounted near the center of the switchgear. **(FIGURE 3*a*)**



CIRCUIT DIAGRAM for System *A* shows how resistance is controlled directly by action of regulator torque motor. **(FIG. 3*b*)**



SEALED DUST-TIGHT front portion of regulator housing encloses *Rocking Contact* sector, pivoted on jeweled bearings. Ventilated rear section contains resistance elements. **(FIG. 3*c*)**



TYPICAL HAND-OPERATED exciter field rheostat used for manual control of generator excitation. **(FIGURE 4)**

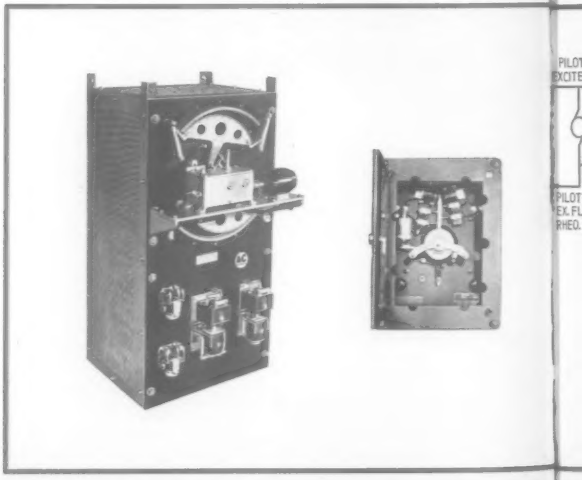
can move into the correct position for the new requirement. Should generator terminal voltage increase, the "lower" contactor closes, inserting additional resistance in the main exciter field. The closed position is maintained until the motor-operated rheostat can adjust itself to the new operating condition.

This type of excitation system, in order to provide accurate generator voltage control, requires a motor-operated main exciter field rheostat having a large number of relatively small resistance steps.

The indirect-acting voltage regulator is used when both main and pilot exciters are furnished with the generator. It can also be used with a main exciter only, provided the main exciter receives its excitation from some constant voltage source, such as the station battery.

System C has additional advantages

In recent years, the rotating-amplifier type voltage regulator has been developed. Initially intended for use with large turbogenerators, it has several advantages not obtainable with the rheostatic-type regulator, and its application has been extended to include hydroelectric units and synchronous condensers.



INDIRECT-ACTING rheostatic voltage regulator used in System *B* has separate voltage-sensing and resistance elements. **(FIG. 5*a*)**

The principal advantage of rotating-amplifier regulators over rheostatic regulators is that minimum excitation can be maintained automatically. Its improved speed of response is also an important advantage in some applications. Under light system loading, system power factor may approach unity, or even become leading. An increase in system voltage resulting from this high power-factor operation may cause the generator voltage regulator to reduce generator excitation below the point required for stable operation at the kw load being carried. Under this condition, the generator may pull out of synchronism should a system disturbance occur.

Rotating-amplifier voltage regulators having the minimum excitation feature automatically maintain sufficient excitation on the generator for the kw load being carried, thus assuring that the generator field current is always maintained above the stable point.

Shown in Figure 6 are the components of a rotating amplifier used for generator excitation control. All of the static control elements are contained in the control cabinet. A comparator circuit compares the generator output voltage with a reference voltage. When the generator output voltage requires adjustment, this circuit sends a signal to the rotating amplifier to either increase or decrease its output voltage. Connected in series with the field circuit of the self-excited main exciter, the output of the *Regulex* generator serves to buck or boost the self-excited exciter field as required by the generator voltage.

The rotating amplifier in effect replaces the pilot exciter used with System *B*. The main exciter operates as a self-excited machine, with the *Regulex* exciter increasing or decreasing its excitation as required by load conditions.

In the event of difficulty with a component of this excitation system, the generator may be operated under manual voltage control by means of the exciter field rheostat. This rheostat, not used for normal operation, can be a simple hand or motor-operated rheostat similar to the one shown in Figure 4, rather than the elaborate type required for System *B*.

System *D* permits direct-connected exciters on large machines

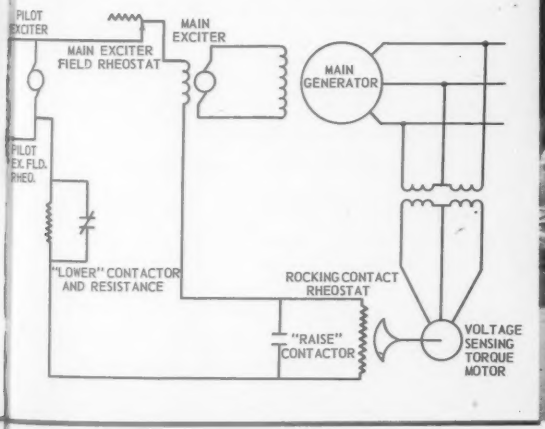
Direct-connected main exciters of the conventional dc generator type can be applied to 3600-rpm generators up to ratings of approximately 50,000 kw at 30-psig hydrogen pressure. On larger units the exciters are usually geared to the generator shaft. For ratings above 150 kw, commutation problems make an exciter speed under 3600 rpm desirable, the speed depending upon the exciter kw rating and voltage.

To permit using direct-connected main exciters for larger generators and to eliminate commutation difficulties, the ac excitation system has been developed. This system consists of an inductor-type alternating current generator, a rectifier, and a static control element.

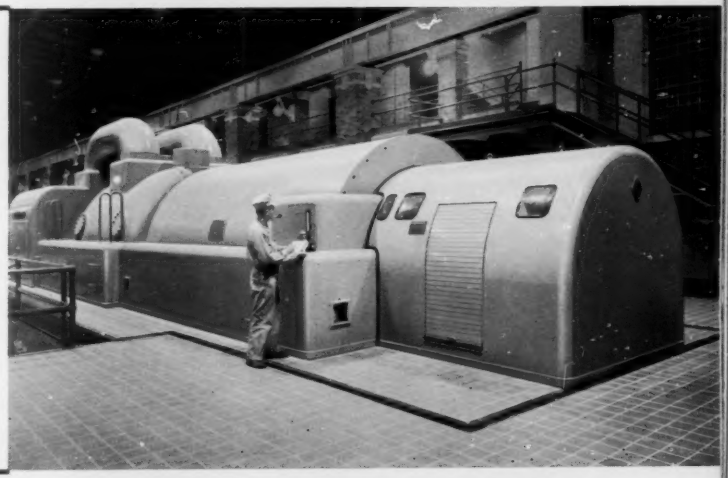
The inductor alternator is one of the oldest types of alternating current generators. The principle of operation is shown in Figure 7. The magnetic circuit of the inductor alternator is magnetized by a dc winding. The air gap between the rotor and the stator varies with the rotation of the rotor, since the rotor is non-cylindrical. This variation in air gap causes corresponding changes in the flux density of the magnetic circuit, thereby generating voltage in the ac winding of the generator.

The direct-connected inductor alternator exciter for 3600-rpm machines is built with 14 poles and generates 420-cycle voltage. This higher frequency is advantageous in several respects, as it results in reduced size and improved speed of response for magnetic amplifiers in the circuit.

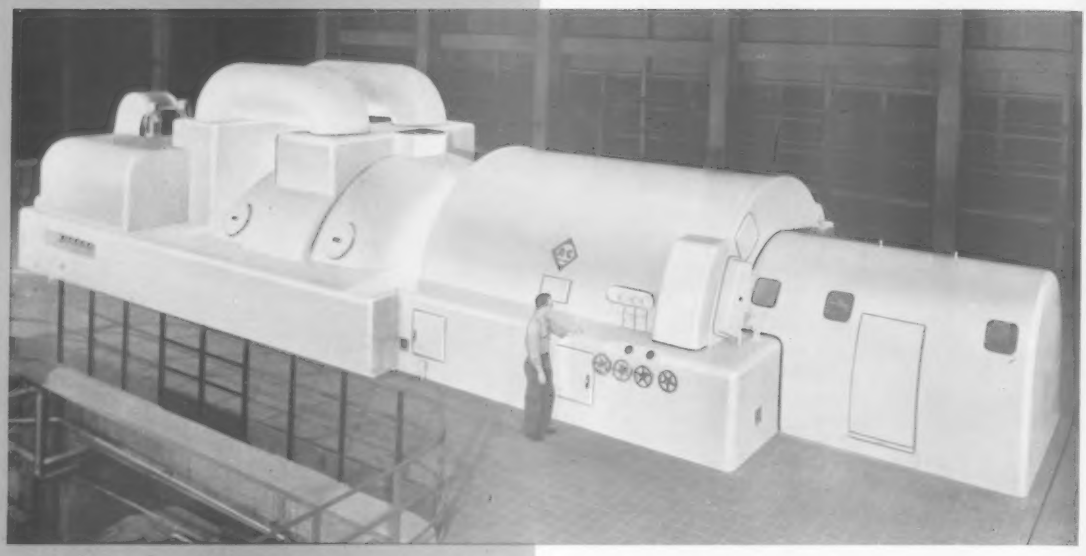
The inductor alternator is very sensitive to the power factor of the load imposed upon it; that is, its voltage regulation varies widely with the load power factor. This characteristic is utilized by the system to regulate generator voltage. Output voltage of the exciter is varied by magnetic amplifiers functioning as a variable reactance load which is added to the kw load imposed by the generator field requirements. This variation in power factor varies



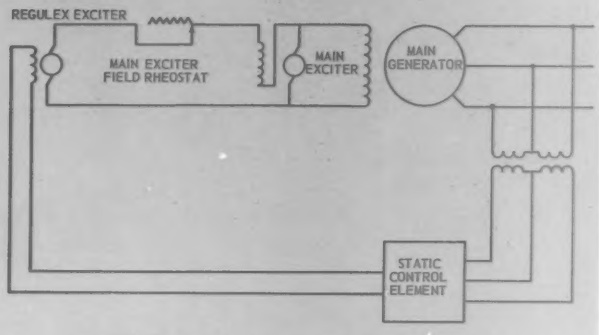
THIS SIMPLIFIED CIRCUIT diagram indicates the pilot exciter, main exciter, and other components of System *B*. **(FIGURE 5b)**



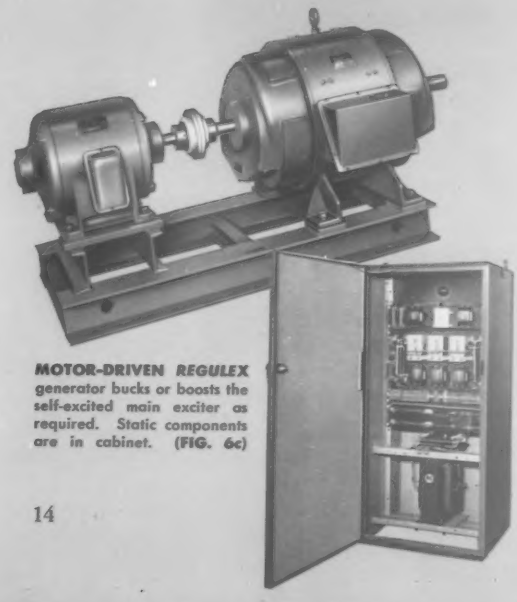
EXCITATION for this 40,000-kw, 3600-rpm turbine-driven generator is provided by excitation System *B*. **(FIGURE 5c)**



A ROTATING REGULATOR, a component of System C, controls excitation of this 66,000-kw, 3600-rpm unit. **(FIGURE 6a)**



EXCITATION SYSTEM C, indicated in this simplified diagram, can maintain minimum excitation automatically. **(FIGURE 6b)**



MOTOR-DRIVEN *REGULEX* generator bucks or boosts the self-excited main exciter as required. Static components are in cabinet. **(FIG. 6c)**

the exciter output voltage over the range required for generator field excitation.

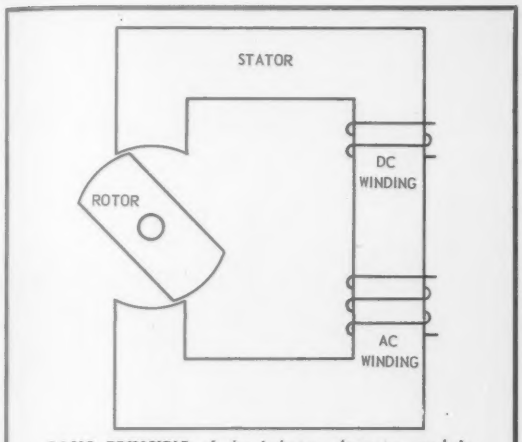
The ac output of the inductor alternator is converted to dc by selenium rectifiers. A cutaway drawing of a typical installation is shown in Figure 8. This rectified current passes through the series-connected generator field and exciter field. In the event of a sudden load change, the induced currents set up in the generator field thus pass through the exciter field also, and results in an immediate change in dc magnetization independent of control operation. This change is in the correct direction to restore the generator voltage to normal.

In this excitation system the magnetic amplifiers are under the control of a static control element similar to that used with the rotating-regulator type excitation system. Control current for the amplifiers is obtained from the main generator potential transformers, through a comparator circuit. These static control elements can also provide the automatic minimum excitation feature described under System *C*.

The inductor alternator excitation system has several advantages. On large units, for example, it can be direct connected to the generator shaft. Speed-reducing gears required with a conventional dc exciter are eliminated. The only moving part is the rotor of the ac exciter, which carries no winding and uses no brushes.

The response obtained with this system is more rapid than with the other systems. Since it is almost instantaneous, exciter response is virtually eliminated as a consideration in the overall response of the generator to a change in voltage. Since the exciter is direct connected, the space requirement is less than that for a conventional exciter and speed reducer.

Component parts of this excitation system, except for the static control panel, are indicated in Figure 8*a*. The rectifier, which must be ventilated, is mounted below the exciter and is ventilated by means of the exciter fan.



BASIC PRINCIPLE of the inductor alternator used in System *D* is to induce an ac voltage by varying the air gap to change flux density of a magnetic circuit. **(FIG. 7)**

Motor-generator exciter sets

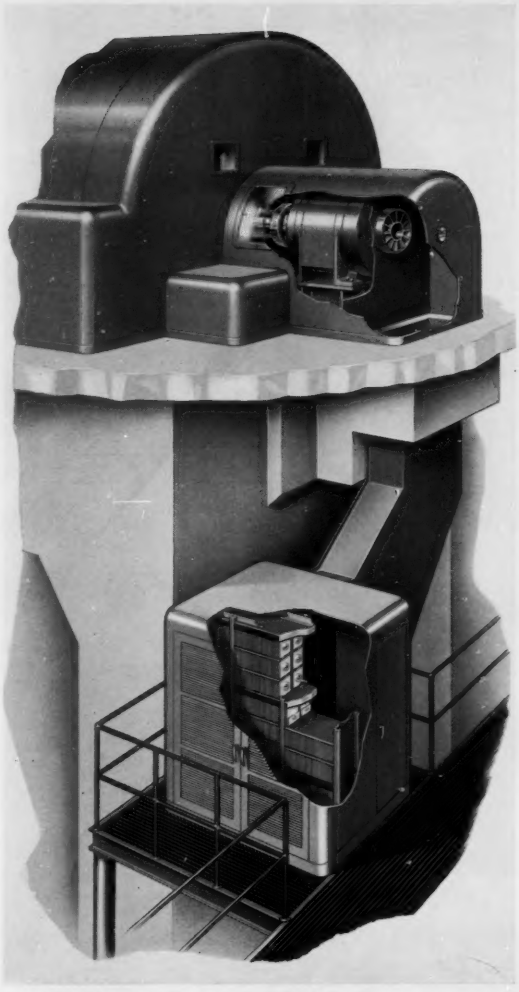
Most central stations have one or more motor-driven exciters for use as spare excitation units in the event of difficulty with any exciter in the station. Such sets are of a sufficiently large rating, to replace the largest exciter in the station. Any of the excitation systems previously described may be used with this arrangement, the only change being in the source of driving power for the exciters.

In some installations of large turbogenerators, direct-connected or geared exciters are omitted, and motor-driven exciters used instead. Since the driving motors for these exciters obtain their power from the station auxiliary circuit, these sets are subjected to interruptions in driving power not encountered when direct-connected or geared exciters are used.

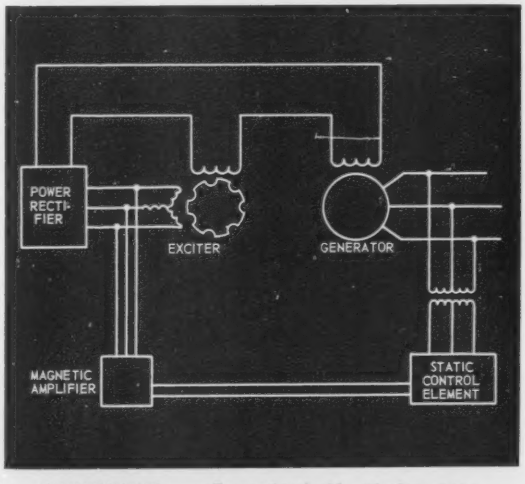
To minimize the possibility of excitation failure under fault conditions on the station auxiliary circuit, the driving motors of sets are built with a very high pull-out torque, usually in the neighborhood of 500 percent. Furthermore, in order to bridge over brief power interruptions in the station auxiliary circuits, these sets are usually provided with flywheels.

A common requirement for a motor-generator exciter set is that it be capable of delivering full excitation to the generator during a system disturbance, with the voltage at the driving motor terminals as low as 70 percent of normal, for a period of one-half second. In addition to high pull-out torque and the use of a flywheel, a high exciter ceiling voltage is used to meet this requirement.

These four basic excitation systems will all give effective control of generator output voltage. Each system may be provided with such features as crosscurrent compensation and line-drop compensation. Because of its simplicity, System *A* is generally used for the ratings where it can be applied. The choice between Systems *B*, *C*, or *D* is generally determined by considerations of exciter rating, desired exciter response, floor space, and automatic minimum excitation requirements. The expected lower maintenance of System *D* may also be of importance.

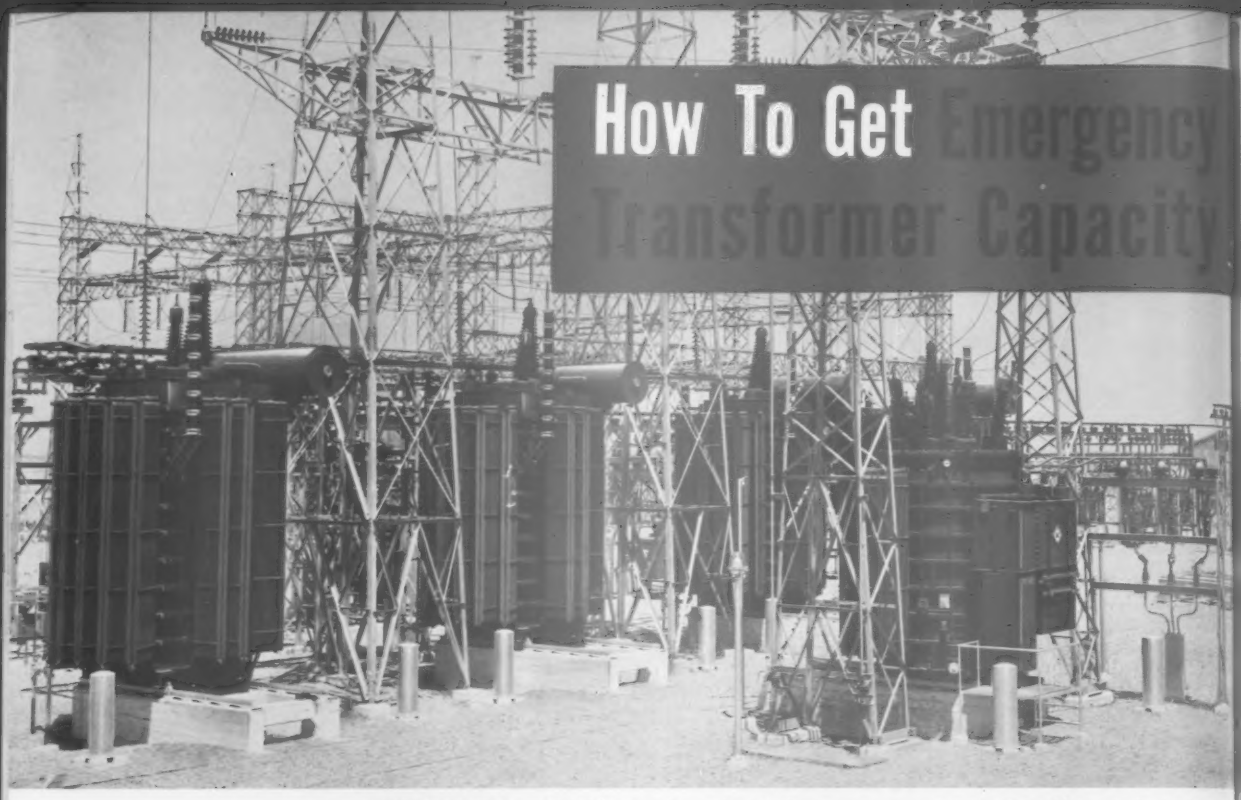


EXCITATION current power rectifiers below generator floor are force-cooled by air ducted to direct-connected fan in exciter housing of excitation System *D*. **(FIG 8a)**



MAINTENANCE normally associated with excitation systems is virtually eliminated by System *D*. Only static control elements are used; commutation is eliminated. **(FIG. 8b)**

How To Get Emergency Transformer Capacity



ADDED COOLING to 100,000-kva transformer bank in large western pumping station would permit the bank to carry more than its rated power for long periods in case of a major shutdown of other transformers in the station.

by S. L. FOSTER
Transformer Department
Allis-Chalmers Mfg. Co.

Here are ways to utilize hidden transformer capacity during a long shutdown of a large power transformer.

EVERY utility or supplier of power faces the problem of maintaining service to his users regardless of conditions that might arise. With the growing size of power equipment, the problem of maintaining continuous uncurtailed service with any piece of equipment shut down has caused much concern. It has been the practice to have sufficient installed capacity so that the largest piece of equipment can be removed from the system without interrupting service. This practice entails additional expenditure for standby capacity. On the other hand, the economies of large equipment cannot be realized without the possibility of curtailing service for maintenance. There is, however, hidden transformer capacity available in most stations that can be utilized during maintenance shutdowns.

Any power transformer meeting ASA Standards will carry overloads up to 200 percent of its normal capacity for short periods of time—not, however, without some sacrifice in transformer life. If the overload requirements are for extended periods, it is not possible to continue such operations without seriously damaging the transformer insulation.

Transformer temperature determines capacity

Since transformer capacity is determined by temperature under load, the load can be increased if the transformer can be kept cool. For specific recommendations on individual units, especially for units with load tap-changing equipment, it is suggested that the transformer manufacturer be consulted to determine the transformer limitations. There are, however, some general rules applying to all transformers that can be used to gauge transformer capacity under extra load. The cooling required for a transformer to carry extra load without sacrifice of life can be provided by lower ambient, fans and blowers, water spray, forced oil circulating coolers, or cooling equipment manifolded from other units.

Conventional transformers have enough cooling equipment mounted on the unit to dissipate the heat generated by the losses in the unit. By increasing the dissipating capacity of the cooling equipment, it is possible to increase the loading on the unit. To determine the actual amount of extra load that can be placed on any transformer when the cooling is increased, the reduction of temperature caused by the increase in cooling capacity is approximated from the curves shown in Figure 1. Then by determining the temperature increase in the conductors over that of the liquid, and consequently the required

reduction of liquid temperature, it is possible to determine the required additional cooling needed to obtain this liquid temperature.

The curves in Figure 2 show the extra copper-over-liquid gradient that occurs with increasing load. To use this curve it is necessary to know the temperature rise of the hottest-spot copper over the liquid 100 percent load. This information is usually available on the certified test report of the transformer. From these curves it is possible to find the hottest-spot temperature for any load. The hot-oil temperature reduction necessary to maintain the windings at normal full-load hot-spot temperature can be found from this data.

Cooling increased by fans

If the transformer has self-cooled radiators, additional cooling may be provided by the addition of fans or blowers to increase the convection cooling. Figure 3 shows the average increase of cooling with an increase of air circulation over the cooling fins. Figures 4 and 5 show how blower fans are mounted in actual installations. Example I demonstrates the method used to predetermine the safe allowable overload capacity of a transformer which can be obtained by using blowers.

Example I:

To find the extra capacity created when fans are added to blow air at a specified rate over the radiators of a self-cooled unit:

Assume a 20,000-kva transformer, self-cooled, 138-kv class, with a ratio of load loss to no-load loss of 2:1. The maximum hot-oil temperature rise at full load is 55 C, and the hot-spot copper gradient over top oil is 10 C. Air will be supplied at a rate of 0.04 cubic feet per minute per square inch of cooling surface using vertical blowers only:

The added cooling capacity of the radiators can be determined from the curves of Figure 3. At 0.04 cu ft per min per sq in., cooling is 200 per cent of self-cooled.

It is necessary to assume probable capacity for the new cooling. Probable capacity = 135 percent.

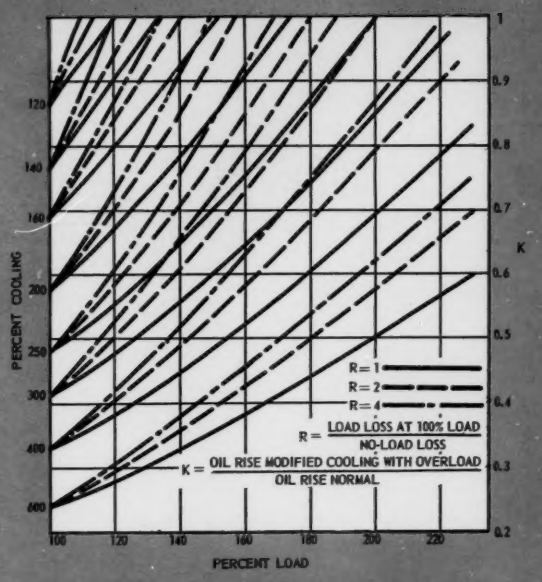
The hot-spot copper temperature above hot oil can be determined from Figure 2. When copper over oil at 100 percent load is 10 C, temperature rise of copper over oil at 135 percent load equals 17 C.

Since it is desired to keep the same copper temperature with the overload, the maximum allowable oil temperature is 65 — 17 = 48 C.

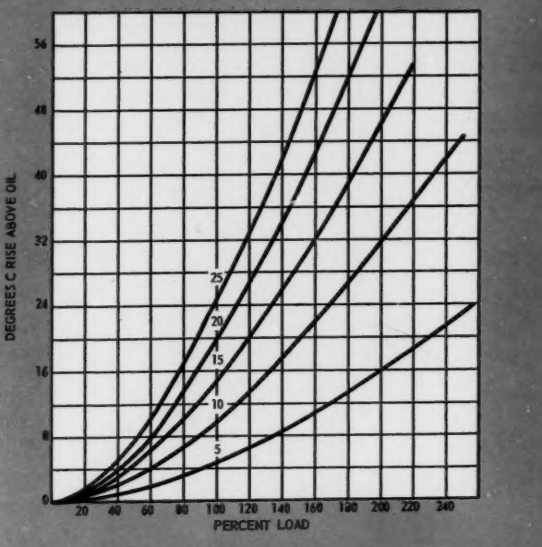
$$\text{Ratio } \frac{\text{oil rise forced air}}{\text{oil rise self-cooled}} = \frac{48}{55} = .0.87$$

From the information of ratio of load loss to no-load loss, percent additional cooling, and ratio of oil rise it is possible to determine an allowable overload capacity from the curves of Figure 1. Allowable load = 140 percent when $R = 2$, $K = 0.87$, and cooling = 200 percent.

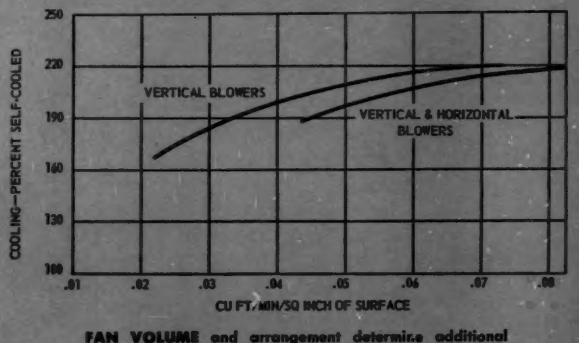
The first assumption for the calculation of load may


PERCENT COOLING
PERCENT LOAD
K
R = 1
R = 2
R = 4
R = LOAD LOSS AT 100% LOAD / NO-LOAD LOSS
K = OIL RISE MODIFIED COOLING WITH OVERLOAD / OIL RISE NORMAL

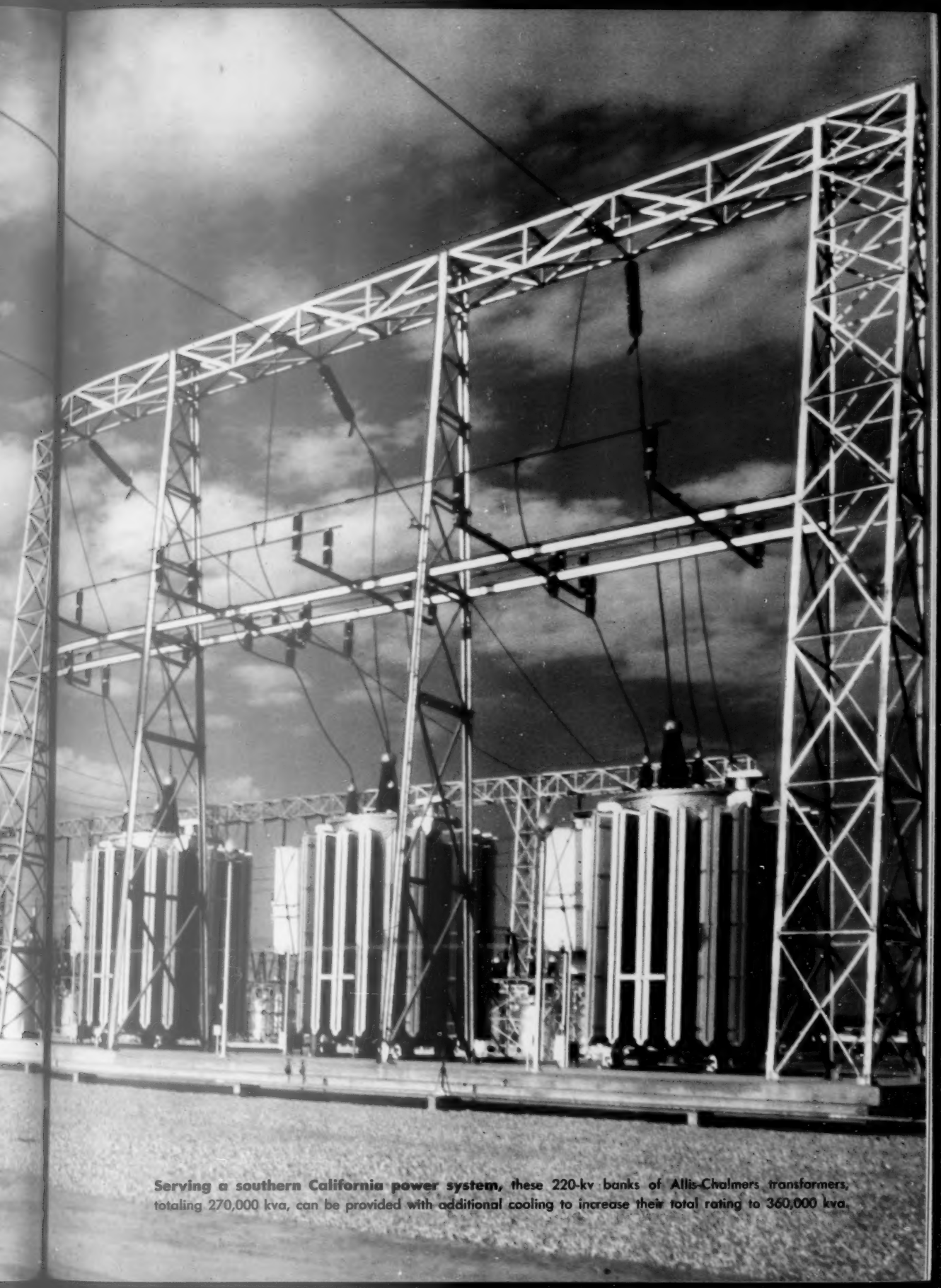
GREATER OVERLOADS are permissible when normal oil temperature rise is reduced by additional cooling. **(FIGURE 1)**



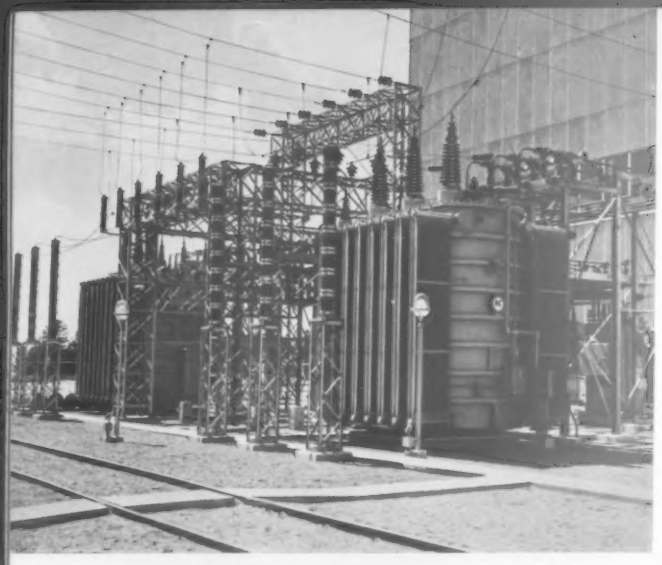
TEMPERATURE GRADIENT between hottest-spot copper and liquid temperature increases with additional load. **(FIGURE 2)**



FAN VOLUME and arrangement determine additional cooling capacity that can be gained with blowers. **(FIG. 3)**



Serving a southern California power system, these 220-kv banks of Allis-Chalmers transformers, totaling 270,000 kva, can be provided with additional cooling to increase their total rating to 360,000 kva.



VERTICAL FANS mounted under the radiators, as shown on these units, may provide the needed extra cooling. **(FIGURE 4)**

not prove to be correct. That is, the answer obtained on Figure 1 may not be the answer assumed to start the problem when obtaining the copper gradient on Figure 2. The overload capacity is approximately the average of the assumed load and the calculated allowable load.

Therefore, probable overload capacity $= \frac{140 + 135}{2}$

$= 137.5$ percent.

The correctness of this approximation can be checked by proceeding through the calculations again, using this average value as the assumed value.

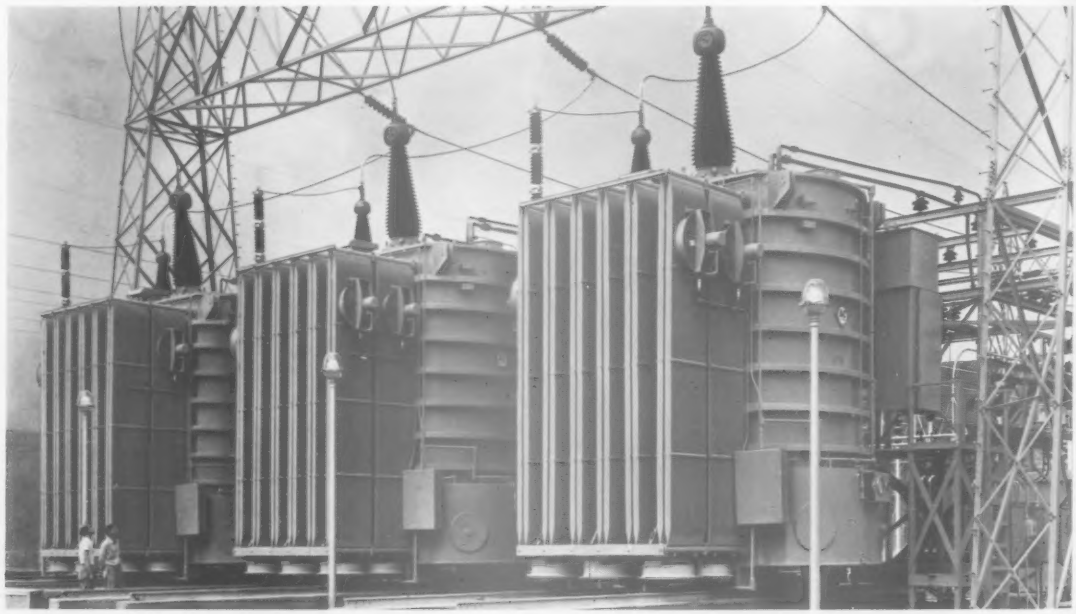
Other cooling means used

If the required increase in capacity exceeds the capabilities of the blowers, other means can be used to increase the capacity. One method which can be used on many self-cooled transformers with forced-air cooling is to add additional cooling radiators to the transformer. When two units of the same design are installed in a station, the cooling radiators from one unit will fit the other unit. Therefore, when one unit is removed from service, the cooling radiators from that unit can be connected to the other unit to increase its cooling capacity. Several radiator arrangements can be made on units in service as shown in Figure 6.

In new installations provisions can be made for transferring coolers as shown in Figure 7. Usually extra cooling equipment added in this fashion does not perform as efficiently as that mounted directly on the tank, so compensation must be made in the cooling capacity calculations. Radiators added as shown in Figure 6 will usually be capable of adding about 80 percent to 85 percent of the capacity of similar units directly mounted on the tank. Those added as shown in Figure 7 will give 90-92 percent of the capacity of similar units mounted directly on the tank. Example II shows the amount by which a transformer can be overloaded with extra cooling equipment added.

Example II:

Overload capacity of the transformer of Example I can be computed in the following manner if it has radiators as shown in Figure 6 and if header pipes are provided for additional radiators as shown in arrangement *B*.



ADDITIONAL COOLING can be gained by using horizontal fans with the vertical units, as shown on these single-phase, 50,000-kva transformers. **(FIGURE 5)**

Number of radiators on transformer originally = 10.

Number of radiators on transformer after modification = 18.

Percent cooling capacity modified = $\frac{18}{10}$ x 200 x 0.85 = 306 percent.

Assume load capacity with this cooling will be 165 percent of self-cooled capacity.

Temperature rise of copper over oil at 165 percent load, taken from Figure 2, is 23 C.

Since maximum allowable hot-spot copper is 65 C, the allowable oil rise = 65 — 23 = 42 C.

$$\frac{\text{Oil rise modified}}{\text{Oil rise original}} = \frac{42}{55} = 0.76$$

The allowable load is 165 percent when $R = 2$ from Example I, 306 percent cooling, and $K = 0.76$ from Figure 4.

Moving radiators or coolers to gain overload capacity in a unit may not be convenient, especially where quick changes might be required. In these cases coolers may be grouped and mounted separate from the transformer tank and valve-connected transformer, so that part of the coolers serve each transformer. With this arrangement a group of coolers can be readily connected to another unit for emergencies without making mounting or plumbing changes.

Where forced-cooling equipment is used, the banking or manifolding of the cooling equipment for several transformers of a bank may prove very desirable. The method of obtaining the capacity of such an installation is calculated by the same means as previously outlined and is shown in Example III.

Example III:

Compute the load capacity of one transformer of a combination of two forced-oil-cooled transformers with manifolded coolers when all the coolers are connected to it.

Two forced-cooled transformers rated 115 kv — 13.8 kv, 550 BIL, with 40 C top oil temperature rise and 65 C hotspot copper rise.

The ratio of load loss to no-load loss is 4:1.

Assume that one transformer will have a probable 120 percent capacity with all coolers connected to it (200 percent cooling).

Copper over oil gradient is 33 C (from Figure 2).

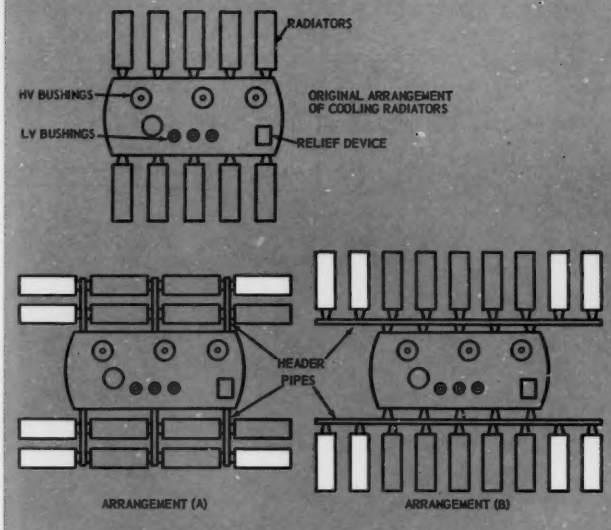
Maximum allowable oil rise is 65 minus 33 or 32 C.

$$\frac{\text{Oil rise 200 percent cooling}}{\text{Oil rise 100 percent cooling}} = \frac{32}{40} = 0.80$$

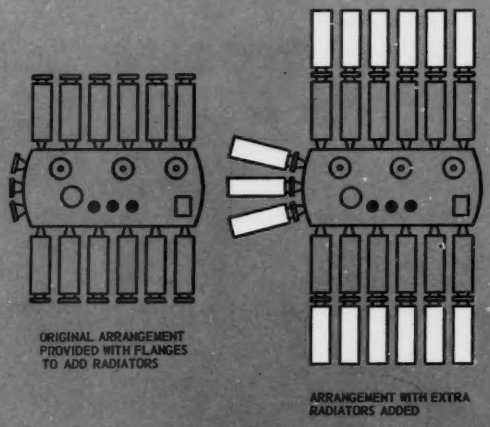
From Figure 1 the allowable load is 128 percent when K is equal to 0.8 with 200 percent cooling.

Approximate allowable capacity is

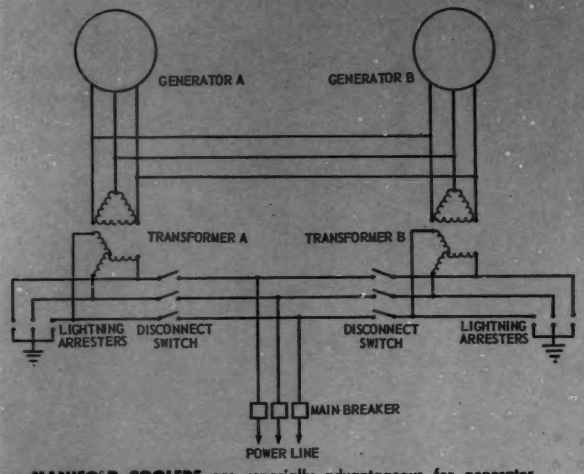
$$\frac{120 + 128}{2} \text{ or } 124 \text{ percent.}$$



ADDITIONAL RADIATORS may be the answer. The extra radiators can be taken from a unit which is out of service. **(FIGURE 6)**



FLANGES can be provided on new transformers to mount the additional radiators. **(FIGURE 7)**



MANIFOLD COOLERS are especially advantageous for generator transformers used with cross-compound turbine-generators. **(FIG. 8)**

NEW SYSTEM of cooling for large power transformers operating in parallel has *Electro-Coolers* mounted on manifolds running between units. Model shows one of many arrangements, in which all coolers may be used with either transformer. **(FIGURE 9)**

Separate grouping of thermosyphon-type radiators is not generally practical, since the extra distance required for the liquid to flow reduces the rate of flow and the capacity of the radiators. These radiators also add somewhat to the cost of the installation. The extra cost may be justified if frequent radiator changes are contemplated in order to carry overloads.

TABLE I

COST OF PROVIDING 100% LOAD CAPACITY WITH LESS THAN 100% FIRM CAPACITY 200,000-KVA STATION, 138 KV — 13.8 KV FORCED-OIL-COOLED TRANSFORMERS

Installation	Percent First Cost	Efficiency at 200,000 Kva	Percent Power Cost	Percent Total Cost
(a) 1 — 200,000-kva unit, 0.0% firm capacity	54.5	99.46	45.5	100
(b) 2 — 100,000-kva units, 50% firm capacity	63.5	99.37	54.5	118
(c) 2 — 100,000-kva units with manifold cooling, 61% firm capacity	63.5	99.37	54.5	118
(d) 3 — 66,667-kva units, 66.67% firm capacity	71.5	99.32	59.5	131
(e) 4 — 50,000-kva units, 75% firm capacity	84.5	99.24	64.5	149
(f) 2 — 122,000-kva units with manifold cooling, 75% firm capacity	73.5	99.46	45.5	119

Firm capacity is capacity of station with one unit out of service.

Manifold coolers provide savings

A manifold cooling system is especially advantageous with two transformers each connected to a generator of a close-coupled cross-compound turbine-generator unit. The electrical power circuit of such an installation is shown in Figure 8, with typical station layouts shown in Figures 9 and 10. In these installations forced-oil equipment is used and the coolers are connected in a bank between the transformers. Normally, the transformers are arranged with a parallel input and with their output connected to a high voltage station bus. Transmission lines are connected to this bus, and the lightning arresters are connected directly to the bus for best protection. If the station is constructed according to the arrangements shown, the arresters, low voltage parallel connections, cooler piping and high voltage bus can be mounted on one set of supports. Normally, each transformer will operate with its own coolers and with valves in the line between the cooler groups closed. When it is necessary to remove one transformer from service, the valves can be opened at the center of the cooler bank and closed on the end from which the transformer is to be removed. This operation transfers all the coolers to one transformer. With the manifolding of coolers in this fashion, it is possible to remove one transformer physically from the site while carrying the firm capacity on the other unit. The firm capacity is the capacity of the combination of one transformer and all the coolers, but with the other transformer removed from service.

Costs are compared

The advantages of manifolding coolers to obtain firm capacity in an installation are demonstrated by the values shown in Table I. The base cost of the station is taken as the total cost of one unit which will carry the load requirements, including the capitalized cost of the power

required for losses. Such an installation, however, has no firm, or standby, capacity. If the firm capacity is obtained by increasing the number of units in the station, first cost as well as the total overall cost of the station, including the capitalized cost of power, is increased rapidly. Firm capacity can be obtained with manifolded cooling installation (*f*) at 11 percent reduction in first cost and a 30 percent reduction in total cost over single units, installation (*e*). This cost does not include foundations, steel work, switchgear and maintenance of the extra units of installation (*e*). For two units of the same capacity the firm capacity can be increased 11 percent by manifolding the cooling, as noted in the comparison of costs and capacities of installations (*b*) and (*c*).

If it is desired to maintain a firm capacity at the minimum cost, the comparison of the costs can be seen in Table II. The total power cost was capitalized at $300 per kilowatt in this installation, and the efficiency was computed by having all transformers connected with equal loads on each unit—the loading being from 50 percent to 80 percent load, depending upon number of units used. This method gives the minimum power cost for the installation. Considering individual units only, the minimum first cost and minimum total cost occur when three units are used. These figures reflect only the cost of the transformer and its losses. If cost of installation and maintenance were included, there might be little difference between the cost of the two-unit and the three-unit installations.

Today, the cost of two transformers with manifolded cooling has a saving of 9 percent over the minimum cost of individual units on the total cost basis. First cost is also below that of the individual unit installation by 1½ percent. If the cost of installation and additional station parts were included in this comparison, a saving of as much as 20 percent could be realized in the cost of maintaining a fixed firm capacity in a station. These are values for a particular installation, but it is also apparent that for the same price a station can be arranged to have considerably more firm capacity by the use of manifold cooling on forced-oil transformers.

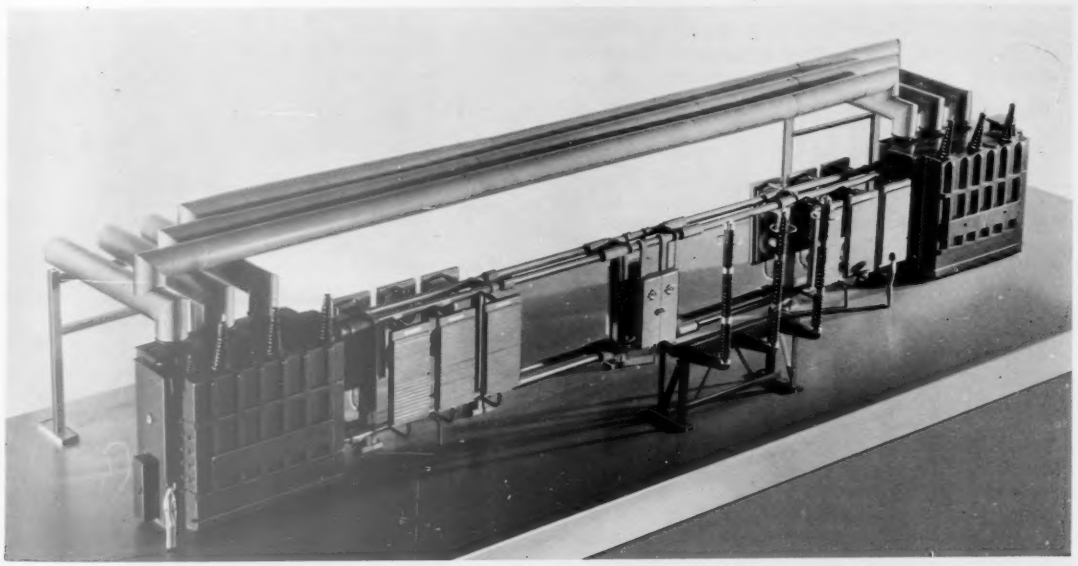
By using the hidden standby capacity that is available, the needed extra capacity for emergencies can often be obtained at little or no extra cost. When planning a new substation or modernizing an older installation, the various methods of obtaining emergency transformer capacity should be planned so that the most economical methods can be employed.

TABLE II

COST OF PROVIDING 100% FIRM CAPACITY 200,000-KVA STATION, 138 KV — 13.8 KV FORCED-OIL-COOLED TRANSFORMERS

Installation	*Percent First Cost	Efficiency at 200,000 Kva (all transformers)	Percent Power Cost	Percent Total Cost
5 — 50,000-kva units	105.5	99.33	57.5	163
4 — 66,667-kva units	95.5	99.39	51.5	147
3 — 100,000-kva units	93.5	99.47	44.5	138
2 — 200,000-kva units	109	99.57	37	146
2 — 162,000-kva units with manifold cooling	92	99.57	37	129

*Percent of total cost of one 200,000-kva transformer plus capitalized cost of losses.



DUAL COOLING arrangement will be used with two 200,000-kva transformers in eastern utility. Each unit is designed to carry 175 percent load continuously when using all the coolers. **(FIGURE 10)**

Current Developments FOR SWITCHGEAR CT's

by **CARL E. MERCIER**
Switchgear Department
Allis-Chalmers Mfg. Co.

New switchgear current transformer design techniques have solved many mechanical, thermal, and electrical problems.

THERE are many unique factors in the application of current transformers in metal-clad switchgear that dictate the selection of insulation and core materials as well as their mechanical arrangements.

Since current transformers are subjected to overvoltage resulting from faults, lightning and switching surges, more care is required in the choice of their insulation than their ratings indicate. They handle not only overload currents accompanying faults but normal overloads as well. In addition, they are required to supply an accurate measure of current for relaying, metering and instrumentation. Because the high voltage bus is isolated from the secondary circuits by the current transformers, their insulation quality assures safety for the personnel who read meters, adjust relays or operate switches. Figure 1 shows how the compact arrangement of current transformers in 13.8-kv metal-clad switchgear makes important their dielectric and thermal design.

The three general types of current transformers used in switchgear are the "doughnut," "through" and "wound" types shown in Figure 2. The simplest is the "doughnut" type, which can be slipped over the switchgear bus. It usually consists of a strip-wound steel core, around which is wrapped an insulated secondary winding.

The "through" type is similar to the "doughnut" type in that the primary winding is only a single turn. The secondary winding is machine wound with pre-cut rectangular laminations stacked into the secondary opening. The primary winding, which usually consists of a bar that is insulated for rated voltage, is slipped into the window and blocked in place.

CURRENT TRANSFORMERS in modern switchgear are designed for com arrangements. Fully cast units shown are rated 15 kv, 1200 amps. (FIGUR

The "wound" type current transformer is the most common. It consists of several turns of primary conductor and a cylindrical secondary coil inserted inside the "eye" of the primary. One leg of the steel pre-cut rectangular laminations is stacked through the opening of the secondary winding. The primary winding may consist of several turns, depending on accuracy and ratio desired, with the only limitation being physical dimensions.

Since the accuracy of a current transformer is mainly dependent on the number of ampere-turns of the windings, it is obvious that the "doughnut" and "through" types have poor accuracy at the low ratios. Usually it is necessary to have 1200 ampere-turns for 0.3 accuracy class.

The mechanical problems can be solved

The CT, of course, must withstand the full mechanical forces resulting from the short-circuit currents to which the switchgear unit might be subjected. These momentary currents are 60,000 rms amperes for 4160 and 40,000 rms amperes for 13.8-kv switchgear. Currents of these magnitudes exert severe forces on current transformer windings. The greatest forces are radial and axial forces, as shown in Figures 3 and 4. The axial force tends to move the primary and secondary coils apart axially. The designer prevents this displacement by proper blocking of the two coils. Either casting the two coils together in high strength casting resin or casting the two coils to the core and frame provides good blocking for the coils. The radial force, on the other hand, tends to increase the primary coil diameter or blow the winding open. Here again casting resin is ideal. However, added strength is obtained

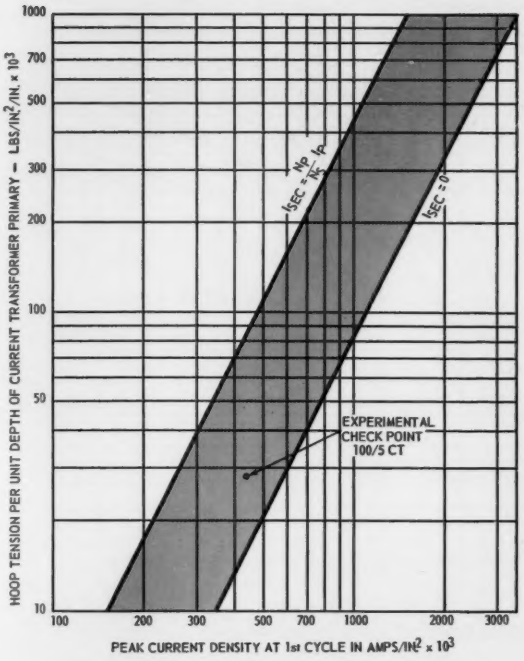
by winding the coil as close to a true circle as possible and by use of a self-locking feature, consisting of a special yoke, which locks the primary coil as soon as force is exerted. Figure 5 shows an early design CT that failed on test at 60,000 amps.

Thermal ability is built in

The thermal problems of the CT are accentuated by its location in the circuit, as well as by its own internal losses. The incoming cables may be connected directly to one terminal of the CT, and the circuit breaker primary disconnect to the other terminal. Either of these terminals may be a source of heating; however, neither can tolerate an appreciable heat transfer from the current transformer. The ambient temperature in which a switchgear CT operates is above the room ambient temperature because of the enclosure. For this reason a standard commercial CT would have to be derated. As a result, switchgear CT must be specially designed for a 50 C rise, based on a maximum copper temperature of 90 C. Switchgear and power circuit breakers are unique among electrical equipment in that they have a 4-second rating. This rating is based on the ability of switchgear breakers to withstand the thermal shock accompanied by high short-circuit current.

Table I shows momentary and 4-second current ratings of switchgear. The CT's must carry these currents without thermal damage. The testing to which a CT is subjected under short-circuit conditions affects mainly the copper and the insulation. The possibility of the copper melting or weakening during heavy currents is the first consideration in switchgear design. It is apparent that both maximum heating and maximum mechanical stresses are applied simultaneously. During faults or high short-circuit currents high copper temperature can be developed inside the current transformer. Figure 6 is a curve showing copper-melting temperature vs. time with various copper sizes. These severe heating conditions make it necessary to specially design CT's for use in switchgear. Many commercial transformers designed for general current-measuring applications are not suitable for switchgear. Since the life of insulation is adversely affected by temperatures and time, a heavy section copper is used to maintain a safe heating temperature in switchgear units.

The curve in Figure 7 shows effects of temperature on the life of Class A insulation during fault conditions. The copper losses are not the only source of heat from

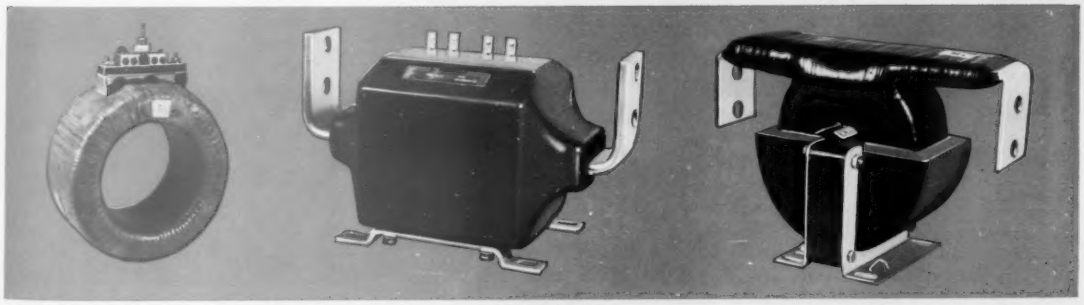


RADIAL FORCES[1] **on switchgear CT primary windings during system short circuits are so severe that special design considerations are required to offset them. (FIGURE 3)**

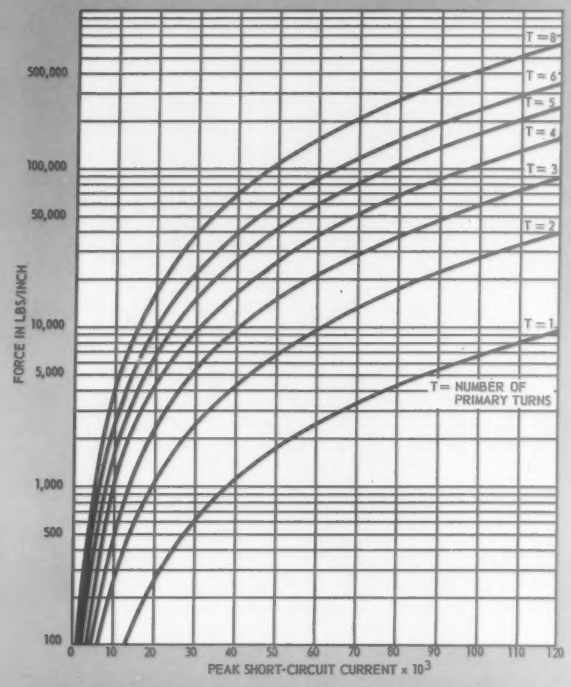
the current transformer. Some of the others are eddy and hysteresis losses in the steel core and stray losses which cause heating in steel plates adjacent to the CT's. Core loss is minimized through the use of low-loss oriented steel. The stray field loss is predominant in "through" type current transformers when they are mounted too close to steel mounting plates. For this reason the core mounting brackets are usually made of aluminum. Figure 8 shows stray field heating effect on steel mounting plates.

Both short-time intense heating and prolonged heating have adverse effects on the insulating materials commonly used in current transformers. Varnished cambric and kraft paper have been the traditional materials used for CT insulation, but both exhibit accelerated aging at rather

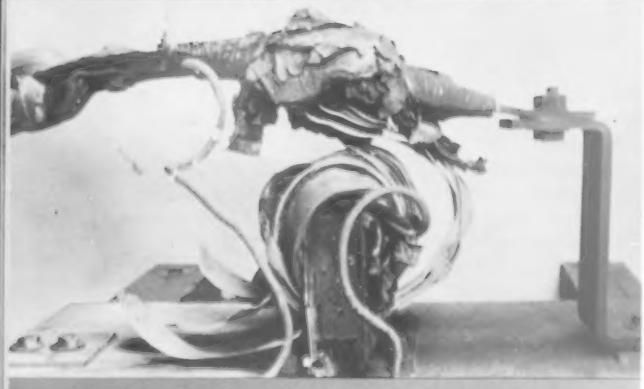
[1] *Instrument Transformers*, B. Hague, Sir Isaac Pitman & Sons, London, 1936.



THREE TYPES of current transformers, left to right, are doughnut, through, and wound. All are used in 15-kv switchgear. **(FIGURE 2)**



AXIAL FORCES tending to separate CT primary and secondary coils are combatted by blocking or casting in epoxy resin. **(FIGURE 4)**



EARLY CT DESIGNS are not satisfactory for modern switchgear. Unit failed short-circuit test required of new CT's. **(FIGURE 5)**

low temperatures. This weakness has led to experiments with many other types of insulation. Insulation heat conductivity is also an important factor to the designer. Casting resins have good heat conductivity with the application of various insulation materials as shown in Figure 7.

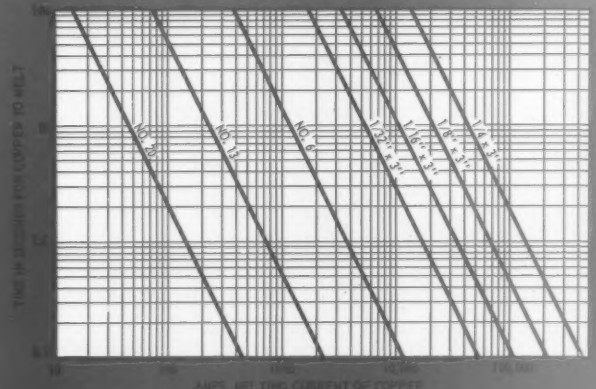
The electrical problems solved

Accuracy and dielectric strength are the chief electrical problems of current transformer design. Switchgear current transformers are required to fall into a given accuracy classification. The accuracy is needed for metering, relaying and differential protection. The accuracy is usually measured at secondary currents of ½, 5 and 100 amps. High accuracies in switchgear are usually obtained by using high ampere-turn windings, and through the use of good grade oriented steel. "U" and "I" punchings have proven efficient for the cores. Figures 10 and 11 show the effects of lamination geometry on excitation and core loss.

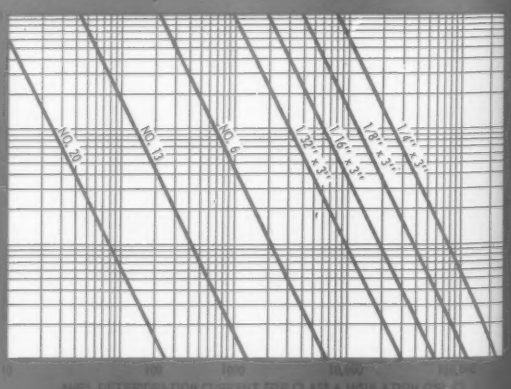
The dielectric strength that is necessary in switchgear CT's is shown in Table II. The high potential strength determines the CT's ability to withstand low frequency switching surges. The impulse level determines ability to withstand lightning strokes or high frequency fault voltages, and the radio noise test determines to some degree the corona level of the CT. Switchgear dielectric engineers, however, often resort to a more accurate method of determining corona levels of CT's by using an oscilloscope method.[2]

Many tests have revealed that the presence of corona not detectable by ear or eye will rapidly deteriorate certain types of insulation. The oscilloscope method is a very sensitive method of detecting the first start of corona. In applying insulation to CT's it is essential, as in all dielectric design, to place the right solid insulation at the high stress points and divide the stress in a dielectric configuration by using the grading principle. Insulation with a low dielectric constant is used where low capacitance is desired, while a high dielectric constant insulation is used where high capacitance can be tolerated. It has been proved that excessive insulation in low air stress areas not only may add higher stresses in critical locations but may cause excessive heating and added bulk to the CT's. Applying insulation in the right place requires an

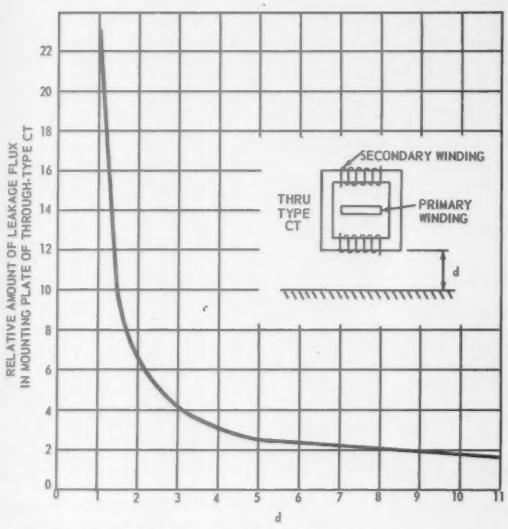
[2] "Corona-Free Switchgear," Carl E. Mercier, Allis-Chalmers *Electrical Review*, First Quarter, 1954.



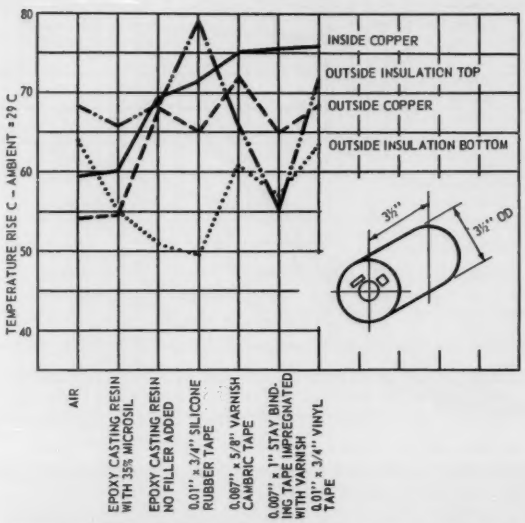
HEAVIER COPPER CROSS SECTION used in switchgear CT's prevents melting of the copper during short circuits. **(FIGURE 6)**



INSULATION LIFE also depends on copper cross section. Lower resistance produces less heating during fault conditions. **(FIGURE 7)**



MINIMUM HEATING in steel plate or framework on which through-type CT is mounted is obtained by increasing the air gap. **(FIGURE 8)**


TEMPERATURE RISE C – AMBIENT = 29 C
INSIDE COPPER
OUTSIDE INSULATION TOP
OUTSIDE COPPER
OUTSIDE INSULATION BOTTOM
AIR
EPOXY CASTING RESIN WITH 35% MICROSIL
EPOXY CASTING RESIN NO FILLER ADDED
0.01" x 3/4" SILICONE RUBBER TAPE
0.007" x 5/8" VARNISH CAMBRIC TAPE
0.007" x 1" STAY BINDING TAPE IMPREGNATED WITH VARNISH
0.01" x 3/4" VINYL TAPE

INSIDE COPPER TEMPERATURE is lowest in CT cast in epoxy resin with 35% microsil filler, compared to other insulation. **(FIGURE 9)**

understanding of the dielectric's electrostatic field in and around a CT. Figure 12 shows the electrostatic field between the high voltage winding and the core.

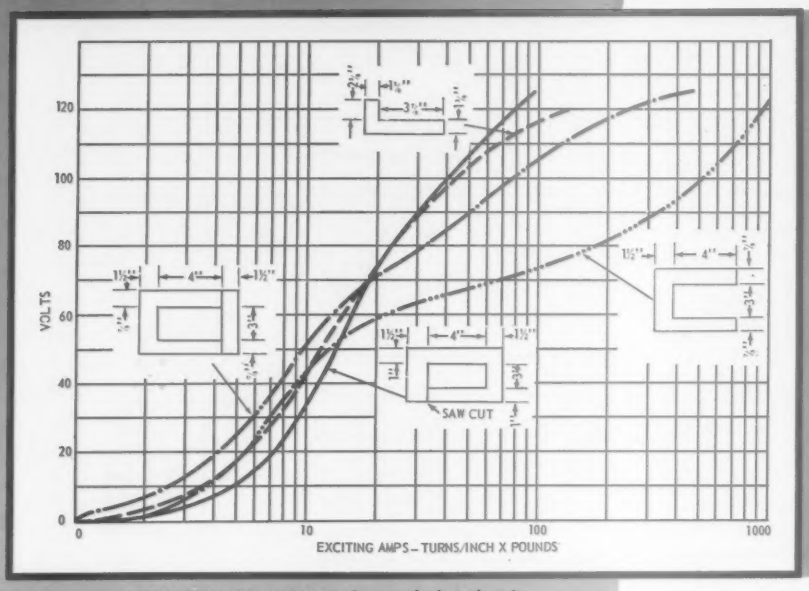
The field map in Figure 12 and the voltage curves in Figure 13 show that the air gaps in the vicinity of the core can be highly stressed. Solid insulation is placed in this area to eliminate the air gap and thus the corona. Through the years, tapes of various types have been used for CT insulation. Tapes are usually applied half lap and are wrapped bulkily at high stress points to attempt to eliminate the high stress air. However, the very nature of taping permits the inclusion of small air films and gaps within the insulation which tend to lower the corona level, and consequently the impulse level. This problem predominates when using cambric and kraft paper tape.

Vinyl tape can also be used in CT insulation. Because it may have an adhesive on one side, it can be wrapped tight enough to minimize air voids. The adhesive also eliminates the tendency to slip, thus permitting good coverage over corners and grooves. However, there are disadvantages to vinyl tapes because they usually have low heat distortion points which are in the range of 100 C.

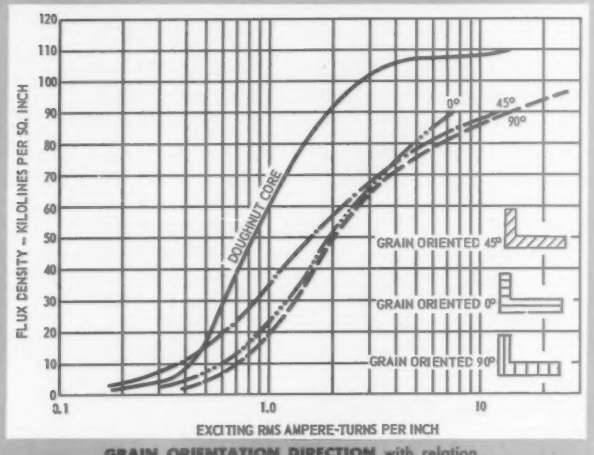
TABLE 1

RATINGS FOR INDOOR OILLESS BREAKERS

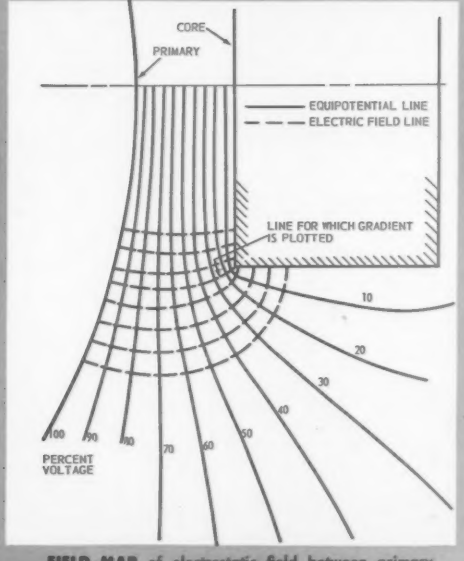
Voltage Ratings			Insulation Level		Current Ratings in Amperes			Interrupting Ratings			
			Withstand Test			Short-Time					
Rated Kv	Max. Design Kv	Minimum Kv for Rated Interrupting Mva	Low Frequency Rms Kv	Impulse Crest Kv	Cont. at 60 Cycles	Momentary	4-second	3-Phase Rated Mva	Amperes at Rated Voltage	Maximum Amperes	Time in Cycles
4.16	4.76	2.3	19	60	600 / 1200	20000	12500	50	7000	12500	8
4.16	4.76	3.5	19	60	600 / 1200 / 2000	40000	25000	150	21000	25000	8
4.16	4.76	3.85	19	60	1200 / 2000	60000	37500	250	35000	37500	8
7.2	8.25	4.6	36	95	1200 / 2000	51000	32000	250	20000	32000	8
7.2	8.25	6.6	36	95	1200 / 2000	70000	44000	500	40000	44000	8
13.8	15.0	6.6	36	95	600 / 1200	20000	13000	150	6300	13000	8
13.8	15.0	6.6	36	95	1200 / 2000	35000	22000	250	10600	22000	8
13.8	15.0	11.5	36	95	1200 / 2000	40000	25000	500	21000	25000	8
14.4	15.5	12	50	110	1200	77000	48000	1000	40000	48000	8



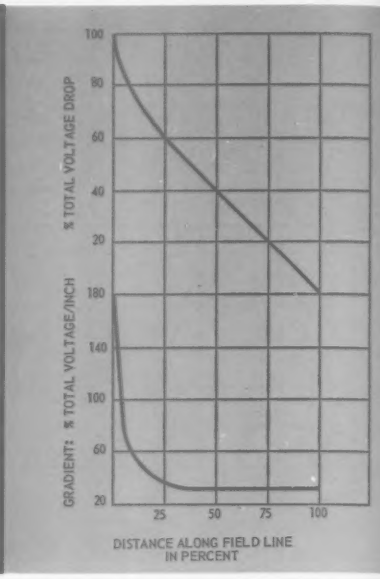
LAMINATION GEOMETRY, stacking methods and grain orientation determine core quality. **(FIGURE 10)**



GRAIN ORIENTATION DIRECTION with relation to lamination shape is important. **(FIGURE 11)**



FIELD MAP of electrostatic field between primary and core is used to determine stress. **(FIGURE 12)**



KNOWLEDGE OF STRESS enables designer to take precautions against corona. **(FIG. 13)**

Also copper tends to erode when in direct contact with vinyl tape.

Various types of rubber have been successfully molded around CT's. Butyl or Neoprene compounds can be applied under high temperature and pressure to the component parts of the CT. While high dielectric strength can be achieved, these particular types of rubber do not have the best mechanical and thermal properties.

Silicone rubber has also been used successfully for insulating CT's and is presently available in three unvulcanized forms: paste, liquid and sheets. The silicones do not cause corrosion and have good dielectric properties. When silicone is applied in sheet form it is placed around the part to be insulated and is then vulcanized. During the vulcanizing cycle, which takes place as soon as the vulcanizing temperature of approximately 350 C is reached, the silicone is held in place with pressure to assure good bonding and a minimum of air voids. Good adhesion to metals can be obtained by using special primers on the conductors.

A current transformer insulated with silicone liquid is shown in Figure 14. Here the silicone is used as a potting compound. The main disadvantages of liquid silicone are cost, high viscosity and shrinkage. Because of its high viscosity it is difficult to handle and to evacuate air bubbles which form when filling a mold. Shrinkage is rather high—3 to 5 percent—causing cracking of the silicone during curing. It appears that silicone in paste form may be better if applied into molds under high pressure, since the paste has lower shrinkage properties.

Cast insulation fills voids

Casting processes allow easy application of the insulating material at the right places in the thickness desired. As a result, intensive investigation of various types of casting or potting compounds is being carried on. The recent improvements in epoxy resins offer promising materials for CT insulation. Figure 15 shows a variety of CT's now being totally encapsulated in epoxy resins.

SILICONE RUBBER has some good characteristics as insulation, but is not as satisfactory as epoxy resin for cast CT's. **(FIGURE 14)**

Epoxy resins are thermal setting compounds of either a hot pour or cold pour material. Hot pour resins require external heat for curing, while cold pour cures under its own exothermic reaction. Epoxy resins can be formulated into either a rigid or a flexible type to suit a given application. Having high tensile, compression and impact strengths, they also have high resistance to moisture and to most acids, alkalies, solvents and oils. In addition, the resins adhere to a great variety of materials. In fact, when resin is chipped off silver-plated surfaces, the silver surface comes off with the resin. As a result, CT's using epoxy resin insulation can be operated for long periods in atmospheres of high humidity and chemical contamination with no adverse effects. The electrical properties of epoxy resins are equally good. Some of these resins have dielectric strengths as high as 1500 volts per mil, and their insulation power factor ranges around 0.005 at 60 cycles. The volume resistivity is as high as 10^{15} ohm-cm.

Many of the electrical and mechanical properties of epoxy resin can be varied or controlled by the filler material used. These fillers can be milled into the resin when it is made or added at the time it is used. Typical fillers

TABLE II

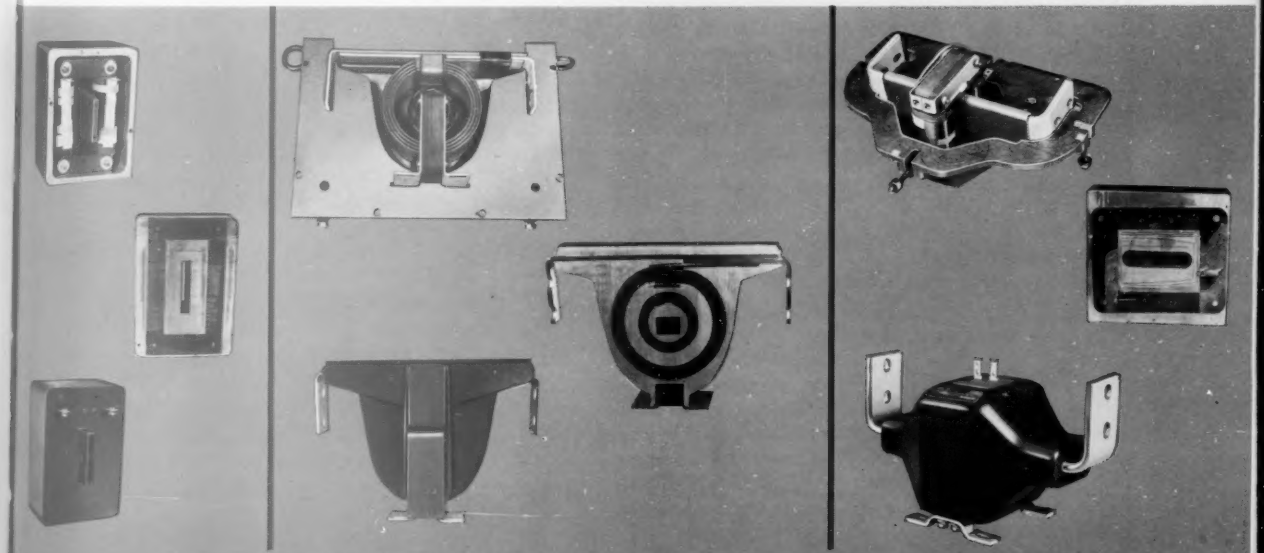
DIELECTRIC TESTS ON CURRENT TRANSFORMERS

Insulation Class	Impulse Level	1-minute to 60-cycle Potential Level	Radio Influence Voltage	
			Test Voltage	Limit Micro-volts
500 v		2.5 kv		
5 kv	60 kv	19 kv	3.34 kv	500
15 kv	95 kv	36 kv	9.41 kv	500

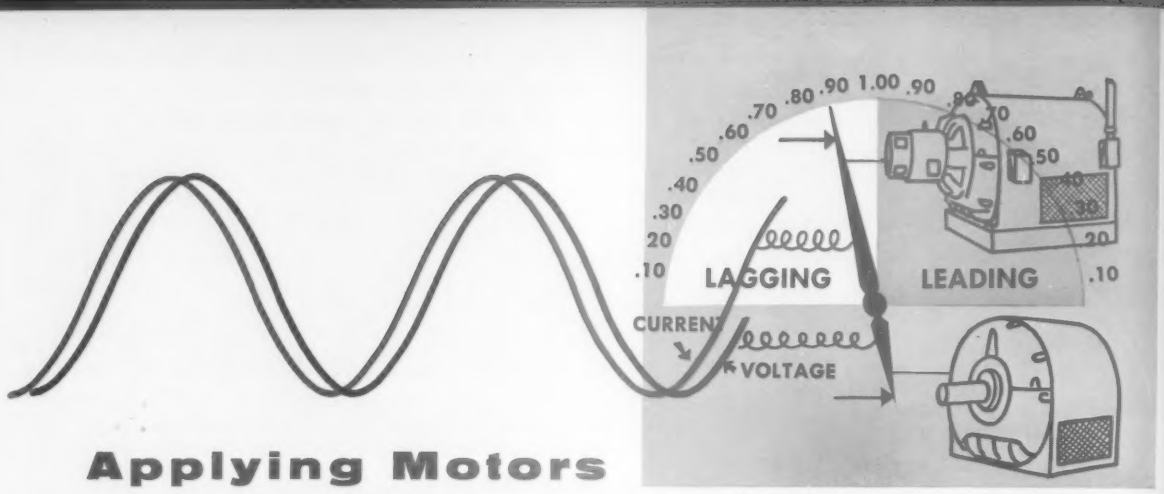
are powders of quartz, microsil, talc, mica, aluminum oxide, magnesium silicate, glass beads. There are also a few negative coefficient of expansion fillers available on the market. However, they cost approximately a dollar per pound as compared to a price of two to ten cents per pound for the others. Glass cloth and mat can also be used in resins to increase mechanical strength.

While some resins are nonflammable, others can be ignited but will not support combustion. This is an important factor in selecting current transformer material. The filler material can be used to control the flame-retardant characteristics of the resin. The amount and type of filler used also has an important bearing on shrinkage coefficient of expansion as well as resin cost. An ideal resin would have low shrinkage, low cost and a coefficient of expansion that approaches the material being encapsulated. Since these ideal properties are not available, in some cases the design engineer has used flexible resins, even though their properties are less ideal electrically and mechanically in the finished product. The flexible resins have made the resins and parts to be cast more compatible for extreme heat cycling conditions.

The variety of new insulation materials as well as oriented core steels and new design technique have greatly improved switchgear-type CT's. They are not only accurate but mechanically and dielectrically stronger. The new designs can better withstand severe short-circuit currents and high switching surge voltages.



CURRENT TRANSFORMERS cast in epoxy resin are far superior to previous designs. The bus-mounted 600-volt class unit, left, is smaller and stronger. All voids are filled in the 15-kv wound type, center, and in the through type, right, thereby eliminating corona. Units are shown in molds prior to casting, cut in half and finished. **(FIGURE 15)**



Applying Motors

TO BALANCE LEADING & LAGGING POWER FACTORS

by **E. N. GIGOT**
Motor & Generator Dept.
Allis-Chalmers Mfg. Co.

Power-factor balancing pays off in reduced power costs throughout entire life of drive motors.

WHEN PLANNING a new plant, an expansion or modernization of an existing plant — or even the replacement of equipment — substantial savings may result if drive motors are selected to balance the leading and lagging power-factor loads on the in-plant power distribution system.

If maximum economy is to be realized during the life of the equipment, initial drive motor cost is only one of several factors that must be considered. The cost of operating each motor and the effect of each motor on in-plant system power factor must also be considered. Since electric power companies have greater line losses when supplying poor power-factor loads, some form of power-factor evaluation is included in their rate structures.

When loads are balanced to improve power factor, both the power company's system and the in-plant distribution system benefit. Feeder line losses and transformer losses are substantially reduced. In addition, voltage drop through this equipment is lowered and its capacity increased.

For example, a load power-factor improvement from 75 percent to 95 percent will reduce the feeder line current to the load by about 21 percent, a figure derived by subtracting the ratio of the two power factors from 100 percent. System capacity is increased and voltage drop decreased by like amounts. Distribution feeder losses, being proportional to the square of the current, are reduced by an even greater amount — 36 percent in this example.

Often power-factor correction can be accomplished economically by the use of synchronous motors and static capacitors. For plants requiring at least one motor rated 50 hp or larger, proper selection of a synchronous motor can often be the most economical method of power-factor correction.

Synchronous motors have additional advantages at low speeds and provide a simple means of power-factor adjustment if operated within motor rating limits.

Controlling power factor with synchronous motors

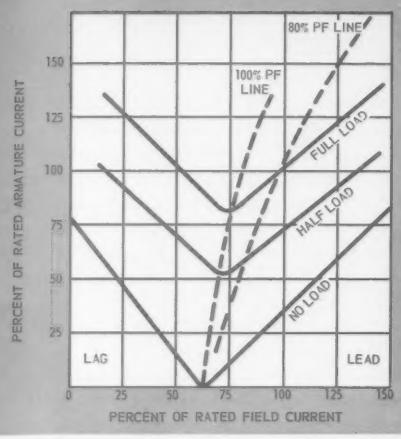
By varying the direct current excitation on a synchronous motor the vector relationship between alternating current and voltage is changed. Changes in loading also change this angular relationship. The typical V-curves in Figure 1 show how the armature current of a synchronous machine varies with changes in excitation or load.

For any given load within the capacity of the motor, there is a field excitation value at which armature current is minimum. This is the unity power-factor point. With greater excitation current, the machine is considered overexcited, and with less excitation it is considered underexcited. These are handy terms to use in discussing reactive control on a power system.*

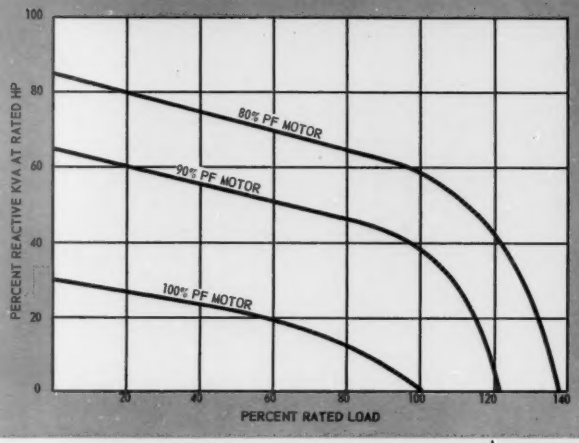
Overexcited synchronous motors, overexcited synchronous generators, and shunt capacitors supply reactive power to the system. On the other hand, induction motors, transformers, and other inductive loads are considered underexcited, since their magnetizing currents make up the reactive power absorbed by this class of equipment. Balance is achieved when the overexcited elements of a system balance out the underexcited elements.

Most synchronous motor drives operate with field excitation set for a rated power factor, usually 80 percent leading when corrective effect is desired. Where maximum efficiency is desired and there is no need for corrective capacity, synchronous motors are usually rated 100 percent power factor.

* "Speaking of Power Factors," R. A. Gerg, 4th Quarter, 1955 ELECTRICAL REVIEW.



POWER-FACTOR CORRECTION obtained from synchronous motors can be varied as indicated by typical V-curves. **(FIGURE 1)**



REACTIVE KVA available from synchronous motors for power factor balancing at various loads is indicated by these curves. **(FIGURE 2)**

Synchronous motors designed for power-factor ratings between 80 and 100 percent are seldom used because their corrective effect is less but their cost is the same as 80 percent pf machines. Motors designed to supply larger amounts of reactive power (60 or 70 percent for example) are also seldom used because they are more costly and less efficient than 80 percent pf motors. Usually, large users of motive power have found it most economical to use the standard ratings of 100 percent or 80 percent.

The fact that synchronous motors provide increased reactive power at part load is a consideration in evaluating their corrective effect. Conversely, overloading reduces their effect in kvar balancing. Since drives almost always operate at something less than full motor horsepower ratings, except for intermittent or emergency periods, this normally is not a problem.

The set of curves in Figure 2, showing the kvar available for any given percentage load on a synchronous motor, applies only when the field excitation is set for the rated power factor of 100 percent, 90 percent, or 80 percent at rated horsepower.

Note that overloading the 100 percent pf motor causes it to operate at lagging power factor and absorb reactive kva, just as an induction motor does.

The standard 80 percent pf motor is flexible enough to operate at unity power factor when kvar requirements are down. However, because pull-out torque is decreased in direct proportion to reduced excitation, a substantial reduction in line voltage or a suddenly applied load can cause the motor to pull out of step. If high pull-out torque is required, an 80 percent pf synchronous motor is usually applied. The high internal voltages and high field strength required for high pull-out torque are provided in its design.

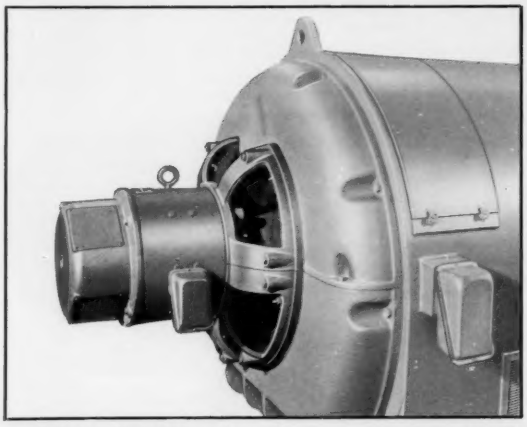
Rubber mill Banbury mixers and pulp mill log chippers typify the widely fluctuating loads to which high pull-out torque motors must be applied. Both of these applications normally use motors with 250 percent pull-out torque, and the load cycling on each is such that momentary loads of close to 2½ times motor rating frequently occur. When synchronous motors are applied to drive them, precaution must be taken in reducing excitation below nameplate rating.

When plant system power factor is at a satisfactory level, 80 percent pf motors not subject to high momentary overloads are frequently operated at reduced excitation, since synchronous motors operated at or near unity power factor give the best efficiency.

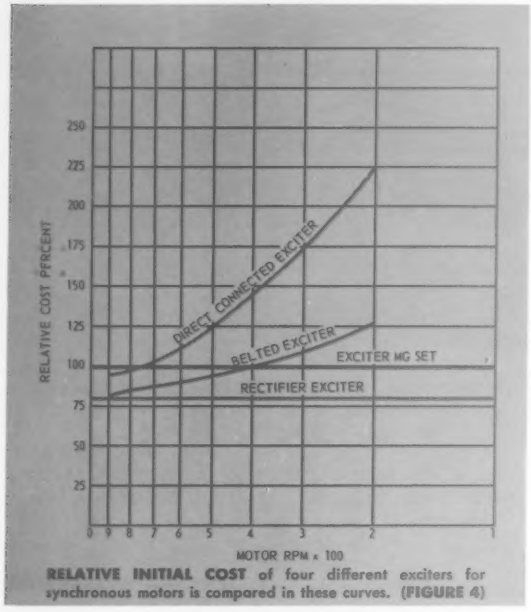
Adjust excitation to control power factor

Excitation systems differ, but all provide some method of adjusting motor power factor. Individual exciters, such as the direct-connected unit in Figure 3, offer the simplest synchronous motor field control. Excitation to the motor field is then varied by a small plate-type rheostat in the exciter field.

When a common source of excitation for several synchronous motors is desirable, a large motor-generator set or rectifier can be used. With a common exciter source, a rheostat or adjustable resistor must be placed in the field circuit of each synchronous motor. For large motors, above 500 hp with ratio of horsepower to speed of greater than one, the extra space required and added rheostat I^2R losses may be objectionable. For example, a motor requiring 15-kw excitation at 125 volts would require a motor field rheostat sized to carry 120 amperes, as con-



INDIVIDUAL EXCITERS, such as this direct-connected unit, provide synchronous motor field excitation which is variable through a simple plate-type rheostat in the exciter field circuit. **(FIGURE 3)**



RELATIVE INITIAL COST of four different exciters for synchronous motors is compared in these curves. **(FIGURE 4)**

trasted to only 5 amperes if the rheostat were located in the field of a typical exciter motor-generator set.

Motor field rheostats for 15-kw capacity and larger are usually separately mounted because of size, and they are motor operated remotely from a control switch on the control panel.

For motor drives not requiring frequent power-factor adjustment, and consequent field current adjustments, a bank of resistors with taps can be used in place of rheostats. These cost only about half as much as the rheostats and usually can be mounted on the motor control. Resistors provide no easy way for power-factor adjustment, since the resistor taps are selected to give rated field current or desired power factor at a given load — with no further adjustments anticipated.

Individual rectifiers can be used to supply excitation for synchronous motors. While not in wide use currently, this system may gain in popularity with the development of new, more compact metallic rectifiers of the semi-conductor type, such as germanium and silicon. Their efficiency is good and moving parts are eliminated. When a rectifier is used, excitation adjustment can be accomplished in either of two ways: by changing taps on the rectifier supply transformer, or by adjusting a rheostat in the motor field.

MOTOR-GENERATOR sets are frequently used for excitation of low speed synchronous motors. This two-bearing motor-generator unit is compact yet accessible for simplified inspection. **(FIGURE 5)**

For slow speed synchronous motors, machines below 514 rpm at 60 cycles, V-belt driven exciters and individual motor-generator sets constitute the most frequently used forms of excitation, since the direct-connected exciter is sizable and the initial cost increases rapidly as motor speeds decrease. The curves in Figure 4 illustrate relative cost of direct-connected versus separately mounted exciters for motors of various speeds.

The exciter motor-generator set has proved to be the most popular source of excitation for low speed motors and for installations where ambient conditions in the motor room make it desirable to locate the exciter elsewhere. The development of a two-bearing set, shown in Figure 5, offers new compactness and ease of maintenance.

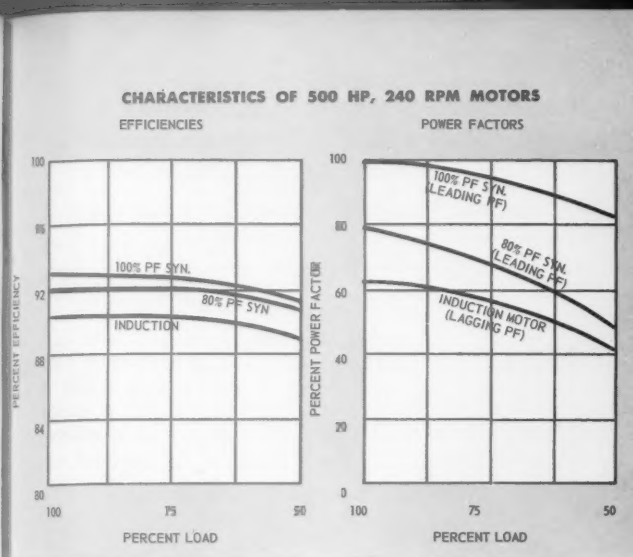
Synchronous vs. induction motors

For many years, synchronous motors have been used almost exclusively for grinding mills, reciprocating air compressors, and similar low speed applications. The efficiency and power-factor curves in Figures 6 and 7 illustrate the power-factor advantages and superior efficiency of a typical low speed synchronous motor. Efficiency alone, for this rating, can save thousands of dollars annually in the power bill, as compared to an induction motor drive.

Other advantages of synchronous motors over induction motors in the low speed ratings are: (1) the initial cost is always less when the ratio of horsepower to speed is greater than one; (2) maintenance and erection are simplified by the generally smaller size, larger air gap, and availability of split rotor construction for mounting on the shaft of reciprocating pumps and compressors like those pictured in Figure 8.

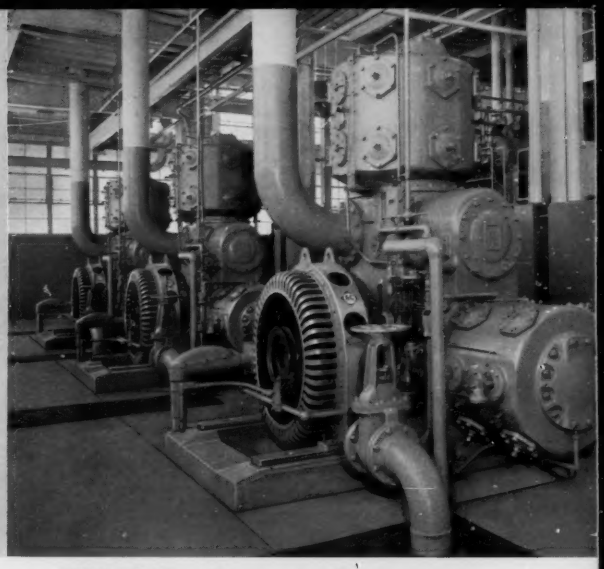
Where motors with rated speeds of 514 rpm and higher at 60 cycles are required, it may be advantageous to apply induction drive motors. If the required drive motor is to have a ratio of horsepower to speed of less than one, induction motors have the following advantages over synchronous motors: (1) initial cost is less; (2) omission of exciters and field application control simplifies operation and maintenance; and (3) induction motor efficiencies are comparable to those of 80 percent pf synchronous motors.

Where plant power factor needs improvement and it is economically advantageous to apply induction motors, capacitors can be added at the induction motor terminals. Capacitor size is usually limited to produce slightly less than 100 percent power factor at the fully loaded motor. Larger capacitor ratings would cause overvoltages and excessive transient torques in the motor from self-excitation as the motor is taken off the line. This applies only when the capacitor is switched on and off with the motor and located between motor and control. On the other hand, locating the capacitor on the power supply side of the motor controller would leave it connected to the system continuously unless separate switching is provided.



OPERATING EFFICIENCY is an economic factor to consider in selecting drive motors. **(FIG. 6)**

PLANT power-factor correction, possible with synchronous motors, can reduce power costs. **(FIG. 7)**



THESE 350-HP synchronous motors, driving compressors in a midwestern factory, help balance plant power factor. They are excited by individual m-g sets. **(FIG. 8)**

Unity power-factor synchronous motors are more efficient at all loads than induction motors of equal rating.

Since induction motor efficiencies, including capacitor losses, are similar to 80 percent pf synchronous motor efficiencies in the high speed intermediate horsepower class, initial cost and maintenance may become determining factors in motor selection. Table I indicates the approximate initial cost comparison between induction motors with separately switched capacitors to produce 80 percent pf lead, and 80 percent pf synchronous motors in horsepower ratings from 100 to 1000 hp. These sizes are commonly used for plant drives, such as centrifugal pumps, motor-generator sets, centrifugal or axial compressors, and fans. Note that motor starters and exciters are included, but installation expense and operating factors, such as maintenance and flexibility of power-factor adjustment, are not included in the comparison.

Economics may determine selection

When adding equipment to correct power factor, the capacitor size required on induction motors, or the most desirable power-factor rating for a synchronous motor, can be determined by making a few sample calculations to determine the effect of the drive in question on plant power factor, and by a study of the power company's rate schedule. Any electric power bill is made up of (1) an energy charge, based on total measured kilowatt-hours consumed, and (2) a demand charge, based on maximum kw or kva used for a 15 or 30-minute interval during the heaviest loading in the billing period. Power factor during the demand period will affect this demand charge, which is often determined by assuming a base power factor, for example 85 percent, and adjusting the charge by the ratio:

$$\frac{.85 \times \text{Measured kw demand}}{\text{Actual power factor}}$$

In other cases, the demand charge is based on straight kva demand and can be lowered with improved power factor. Regardless of the method used, it is necessary to calculate the kvar required to improve power factor, or reduce the kva figure to the most economical value. Raising power factor to 95 percent will usually be economical. Beyond that point, reduced power cost during equipment life seldom equals the cost of kvar capacity required.

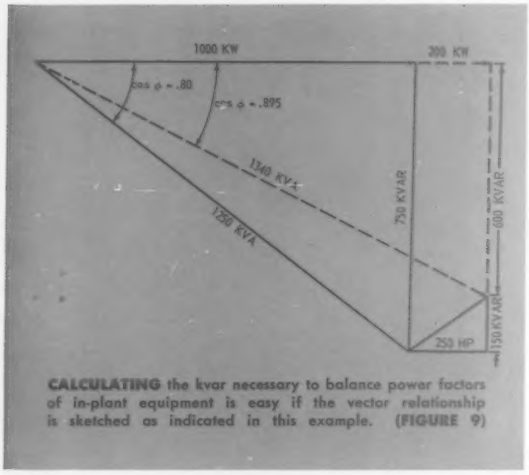
Calculating kvar requirement is easy if the right triangle relationship, Figure 9, is sketched. For example, assume a plant load of 1000 kw, 1250 kva, 80 percent pf lagging. Adding a 250-hp, 80 percent leading pf synchronous motor, operating at full rating, will provide 150 kvar, as indicated in Figure 2. This results in a new total kva load of 1340 at 89.5 pf.

To increase system power factor to 95 percent will require an additional 195 kvar. This can be accomplished by adding capacitors or leading pf synchronous motor capacity. However, in this example, raising system power factor from 95 to 100 percent would require an additional 405 kvar, which is difficult to justify economically. The 250-hp motor could have been rated at 70 percent, 60 percent or greater leading power factor, but at increased cost. The increased motor cost would probably exceed the expenditure incurred by adding capacitors, since a synchronous motor rated 70 percent pf is about 17 percent more costly than one rated 80 percent pf. Calculations will determine whether a unity power-factor synchronous motor or an induction motor with static capacitors is more economical. Although capacitors add only a negligible kw load (they are about 99.7 percent efficient), induction motors add to the kvar absorbed from the system by an amount equal to

$$\frac{\text{Hp} \times .746 \times (\text{Tangent of pf angle})}{\text{Efficiency}}$$

Motor RPM	100 Hp	250 Hp	500 Hp	800 Hp	1000 Hp
1800	225%	135%	115%	115%	120%
1200	165%	115%	100%	100%	100%
900	160%	115%	100%	100%	95%
720	170%	115%	95%	95%	95%
600	170%	115%	95%	95%	95%
514	160%	110%	95%	95%	95%

APPROXIMATE initial cost of 80 percent pf synchronous motors is indicated as a percentage of cost for induction motors with switched capacitors to produce 80 percent leading pf. **(TABLE I)**



CALCULATING the kvar necessary to balance power factors of in-plant equipment is easy if the vector relationship is sketched as indicated in this example. **(FIGURE 9)**

which will require the addition of still more capacitors. Motor speed, equipment cost, rate schedules, and other factors will all affect the economies of application.

Synchronous condensers used by some industries

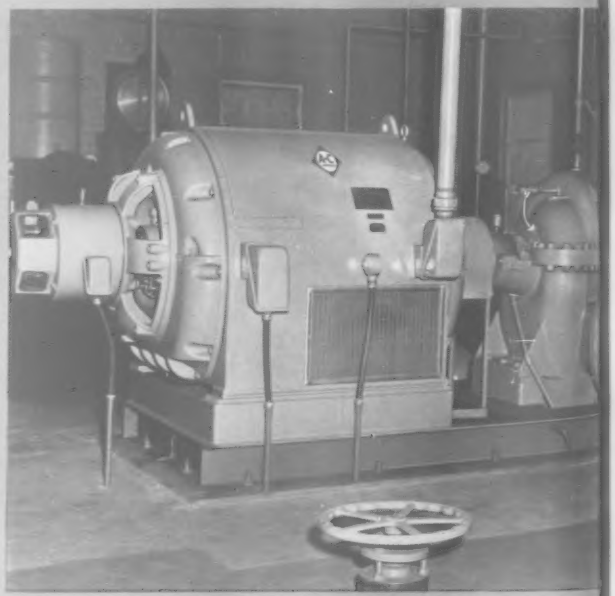
Synchronous condensers are considered the most flexible means of power-factor control. They can provide continuous, close control of power factor. They can either supply or absorb kvar by being operated overexcited or underexcited, respectively. When equipped with high response exciter systems, synchronous condensers also have the ability to maintain stable system voltage under heavy load swings by absorbing or supplying kvars to counteract the load swing. Voltage regulation is therefore their prime function.

Synchronous condensers are limited in their industrial and commercial applications. They are occasionally used where large concentrations of induction motors must operate temporarily under severe emergency conditions with low system voltage, caused by faults or switching operations. A more frequent application today is in the metal industries, where arc furnaces contribute to the requirement for fast control of reactive power in order to avoid objectionable light flicker from the cyclic load swings.*

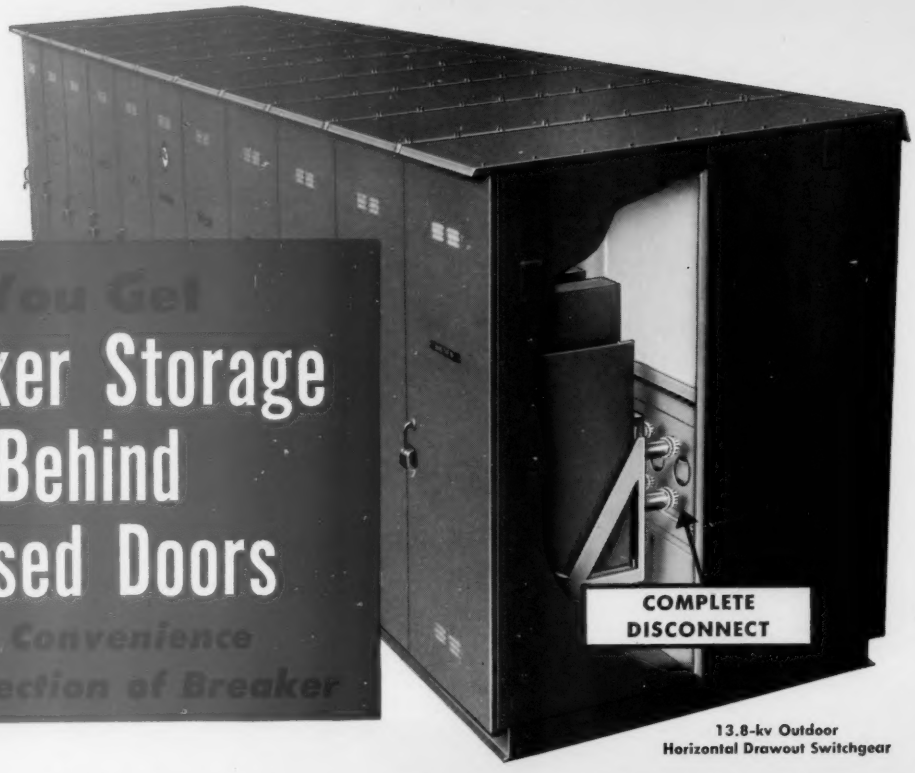
The disadvantages of a synchronous condenser are largely economic. They are seldom considered for ratings less than 5000 kw and then the initial cost is approximately double that of capacitors. Installation cost is higher and the operation cost is greater, since losses are 5 to 10 times greater than capacitor losses.

Selection of large motor drives to balance leading and lagging power-factor loads on a system depends greatly on the results obtained from comparisons that are primarily economic. These include initial cost, operating cost, and the effect of power factor on power rates and distribution equipment. Low speed drives 50 hp and larger always favor the synchronous motor. However, at higher speeds the comparison between induction and synchronous motors requires more consideration.

* "Synchronous Condenser at Arc-Furnace Load Steadies Power Demands," S. E. McDowell, 4th Quarter, 1954 ELECTRICAL REVIEW.



AN INDUCTION motor, rated 600 hp at 700 rpm, drives the pump pictured at left, while a 400-hp synchronous motor with direct-connected exciter has been applied to the pump above. **(FIG. 10)**



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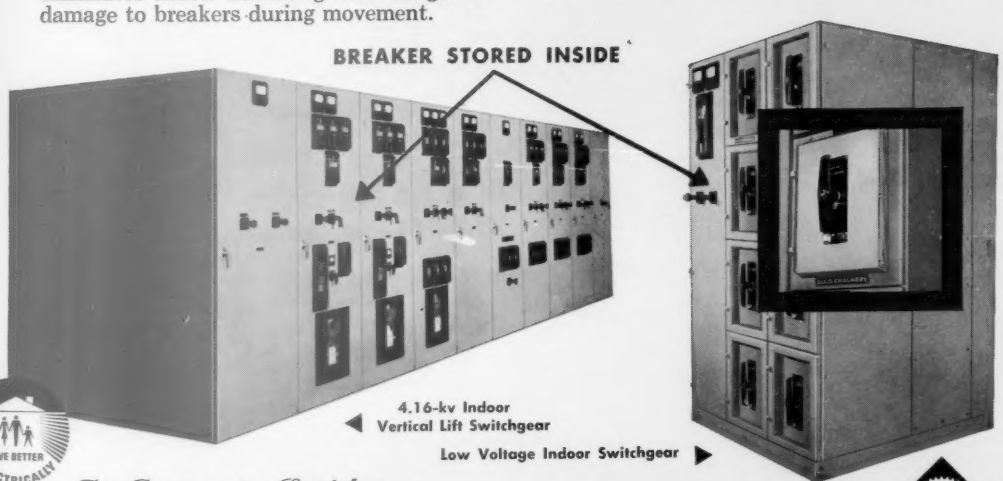

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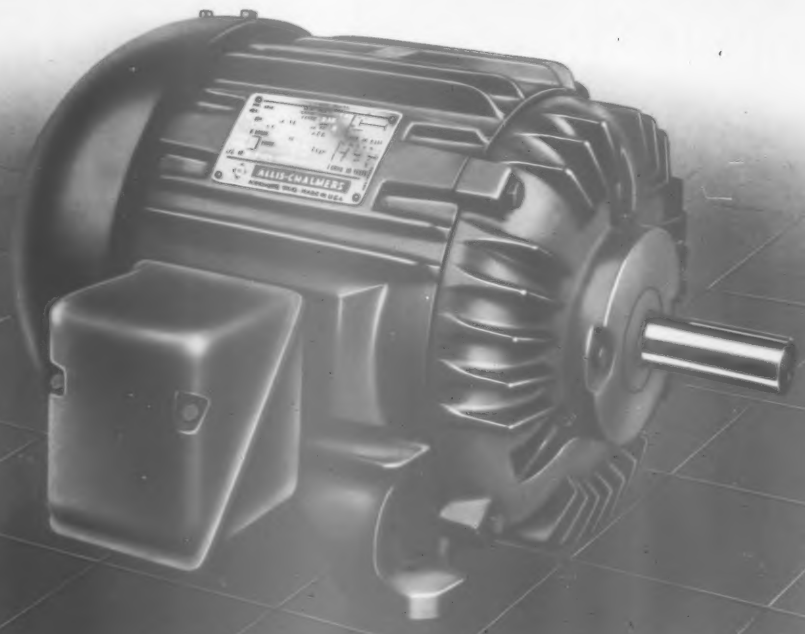
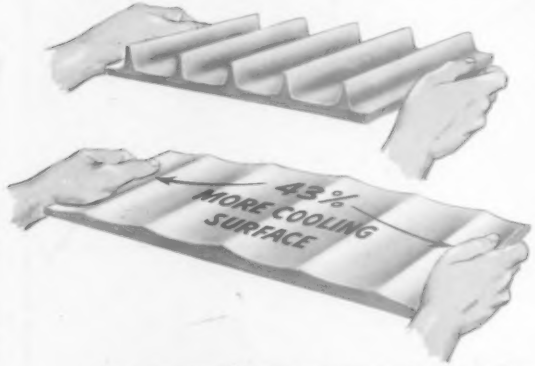


Why Rib-Type Motors Won't Fry



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